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STUDY OF THE ECONOMIC IMPACT OF SULFUR REGULATIONS PROMULGATED BY THE U.S. ENVIRONMENTAL PROTECTION AGENCY FOR OHIO ON AUGUST 27, 1976

STUDY DOCUMENT NUMBER 9. ESTIMATION OF COSTS APPLYING PROPOSED OHIO SO2 REGULATIONS TO INDUSTRIAL PROCESSES AND NONUTILITY FUEL COMBUSTION SOURCES

BATTELLE COLUMBUS LABORATORIES, OHIO

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FINAL REPORT

on

ESTIMATION OF COSTS APPLYING PROPOSED OHIO SO_2 REGULATIONS TO INDUSTRIAL PROCESSES AND NONUTILITY FUEL COMBUSTION SOURCES

to

U. S. ENVIRONMENTAL PROTECTION AGENCY
CONTRACT NO. 68-02-1323
Task 47

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16. ABSTRACT

This report is the ninth volume in support of the Inflation Impact Statement for sulfur dioxide regulations prepared by the U.S. Environmental Protection Agency, to correct deficiencies in the Ohio State Implementation Plan. The Technical Support Document, Volumes I and II may be obtained through the National Technical Information Service - EPA 905/2-76-002, PB-257 694 and PB-257 695.

This document provides basic data on control alternatives and their costs for industry, including process sources, fuel combustion processes, and fossil fuel combustion for steam generation, the latter including nonutility boilers. Data are provided at the stack and boiler levels and include such factors as fuel type, fuel consumption, and design firing rate. In addition, cost algorithms for flue gas desulfurization and industry specific process controls are included.

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INFLATION IMPACT STUDY DOCUMENTATION

This appendix identifies the documents prepared to support the Inflation Impact Analysis of the sulfur oxide regulations prepared by the U.S. Environmental Protection Agency (EPA) for the state of Ohio.

Figure 1 identifies the supporting documents. Document #2 provides an overview of the study methodology and illustrates the depth of analysis contained in the study.

Impact Studies

Documents #3 and 4 are economic impact analyses of the utility and industrial sectors in Ohio. These reports address impacts on prices, output, employment and financial viability. Document #5 summarizes the energy impacts of the regulation in terms of the level of energy demand, shifts from coal to oil likely to occur as a result of compliance with the regulations as well as shifts in coal production patterns. In particular, this report focuses on whether coal production in Ohio, which is generally high in sulfur content, will be adversely impacted.

Cost Minimization

Documents #6 and 7 present the methodology for estimating costs of compliance and the choice of pollution control strategies. For both utility and industry, these supporting documents outline the cost minimizing strategies which provide the basis for the economic and energy impacts discussed in documents #3 - 5.

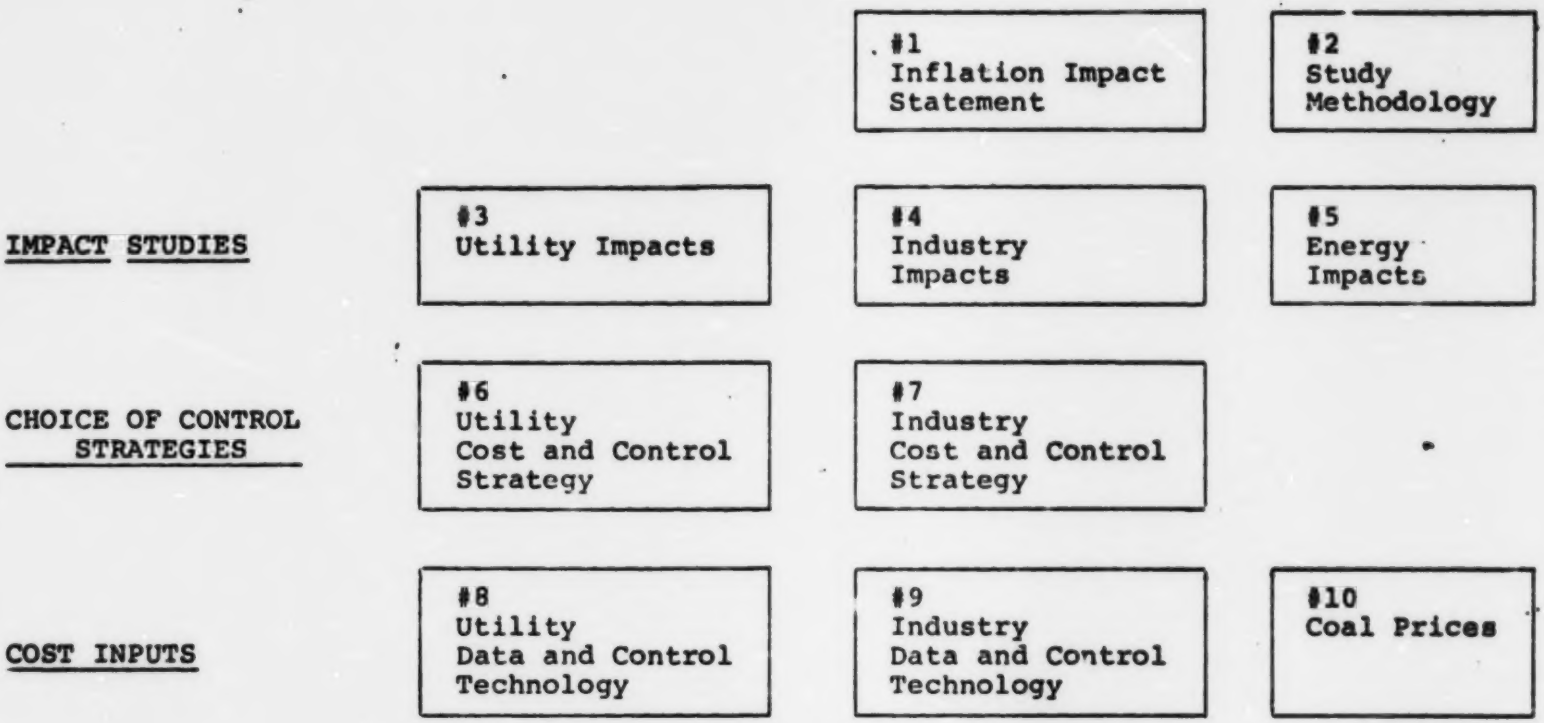
Cost Inputs

These final documents contain the basic data inputs to the study. Document #8 describes the pollution control technology options, their costs plus basic plant specific parameters which influence costs such as fuel consumption and boiler firing rates.

Document #9 contains similar data on the industrial sector. Document #10 presents the derivation of coal prices employed in this study and used in both the industry and utility sector analysis. The focus is on the price premium of low versus high sulfur coal.

Figure 1

INFLATION IMPACT STATEMENTS SUPPORTING DOCUMENTS



EPA-905/5-76-009 323014

This is Document #9, one in a series of nine documents in support of the Inflationary Impact Statement (Document #1).

Management Summary

In support of the directive to assess the inflationary impact of the SO_2 emission regulations proposed by the U.S. EPA for the State of Ohio, the costs of applying these regulations for process and non-utility fuel combustion sources have been analyzed. The data and results have been compiled on a data tape in a format suitable for manipulation by the contractor analyzing the overall inflationary impact and the methodologies for calculation of the costs of applying candidate control technologies alternatives have been developed.

The data base is comprised of the current emissions confirmation inventory compiled by the Ohio EPA, smoothed to correct the errors contained therein. For fuel combustion sources smoothing was done on values outside selected limits by applying a methodology based on basic engineering principles. Errors in process source data were corrected individually; missing data were synthesized on the basis of plant and process characteristics obtained from other independent references.

Alternative control technologies for the abatement of SO_2 emissions from fuel combustion sources were flue gas desulfurization (FGD) and fuel switching to lower sulfur fuels. The principal source of process emissions in Ohio is the combustion of sulfur-containing process gases, refinery gas and coke oven gas. Control technology for sources in this category is based on centralized treatment of the process gas, permitting its subsequent uncontrolled combustion.

TABLE OF CONTENTS

	Page
INTRODUCTION	1
Background	1
OBJECTIVES	2
PROPOSED STANDARDS DATA	2
Fuel Combustion Sources	3
Process Sources	3
ANALYSIS OF THE OHIO SO_2 EMISSIONS INVENTORY	9
Procedure	9
PROCESS SOURCES	15
Petroleum Refineries	16
Amine Scrubbing and Stripping	17
Claus Plant	17
Tail Gas Cleanup	18
Boilers	18
Process Effluents	18
Iron and Steel Plants	19
Coke Oven Plants	19
Sinter Plants	28
Other Metallurgical Processes	29
Chemical Sources of SO_2	30
Sulfuric Acid Plants	30
Zinc Smelter	31
FUEL COMBUSTION PROCESSES	35
Cement and Lime Kilns	35
Brick and Clay Industry	36
Fiberglass Industry	37
Limestone/Gypsum/Refractory Industries	37
FOSSIL FUEL COMBUSTION FOR STEAM GENERATION	37
Constraints and Costs in Changing from High-Sulfur to Low-Sulfur Fuels for Steam Generating Units	38
General Capacity Ranges of the Several Stoker Modes of Firing Boilers	39
Coal Characteristics in Relation to Use in Stoker Firing of Non-Utility Boilers	41
Summary	44
Costs for Switching from Coal-fired to Oil-fired Operation of Non-Utility Steam Generating Units	45

TABLE OF CONTENTS (Continued)

Page

FGD Costs for Non-Utility Boilers 45
Capital Costs 46
Operating and Maintenance Costs 48
Energy Usage. 51
Sludge Production 52
Life of Capital. 53
FGD Sludge Disposal Costs 54

GROWTH ESTIMATES 57
REFERENCES 63-65

APPENDIX A

OUTLINE OF TAPE CONTENTS A1-A3

LIST OF TABLES

Table 1. Allowable Emissions for Fossil Fuel Fired Steam Generators 4-6

Table 2. Total Ohio Non-Utility Fuel Consumption by Fuel Type and Usage 13

Table 3. Total Heat Output of Non-Utility Coal-Fired Heaters/ Boilers by Size 13

Table 4. Total Non-Utility Coal Consumption by Sulfur Class 14

Table 5. Coke Oven Plants in Ohio 20

Table 6. Listing of Coke Ovens and Processing Units Using Cole Oven Gas. 22-27

Table 7. Listing of Sinter Plants 28

Table 8. Values of A and B in the Equation $C+AT^B$ Representing Investment and Operating and Maintenance Costs for Equipping Sulfuric Acid Plants with Dual-Absorption Facilities 32

Table 9. Sulfur Dioxide Abatement Costs for Sulfuric Acid Plants in Ohio 33

LIST OF TABLES
(Continued)

Page

Table 10. Energy Used by Dual-Absorption Abatement of SO_2 in Ohio Sulfuric Acid Plants 34

Table 11. General Capacity Ranges of Stokers and Pulverized Coal-Fired Commercial and Industrial Steam Generating Units 40

Table 12. Some Generalized Constraints Involving Coal Characteristics in Changing From High-Sulfur to Low-Sulfur Eastern Bituminous Coals for Commercial and Industrial Boilers 42

Table 13. Ohio Growth Factors by County and SIC 59-61

Table 14. New Source Performance Standards (NSPS) Applicable to Ohio Industrial Processes which Emit SO_2. 62

LIST OF FIGURES

Figure 1. Allowable SO_2 Emissions for Ohio Counties, Lbs/MM Btu 7

Figure 2. Estimated Cumulative Capital and Operating Costs for Ohio Boilers as a Function of Boiler Size. 11

INTRODUCTION

Background

Following the enactment of the 1970 amendments to the Clean Air Act (P.L. 91-604), it became incumbent upon the states to develop Implementation Plans to achieve and maintain the national ambient air quality standards established by the U.S. Environmental Protection Agency.

On January 30, 1972, the Governor of Ohio, following public hearings, submitted The Ohio Implementation Plan. The Ohio Plan was approved by the EPA Administrator, with certain specific exceptions. Subsequently, amendments were submitted which permitted full approval of the Plan on September 22, 1972.

However, on June 28, 1973 the U.S. Court of Appeals for the Sixth Circuit vacated this approval and remanded the case to the Environmental Protection Agency. Ohio later submitted a revised Plan, which excluded regulations for the control of sulfur dioxide and which was approved on April 15, 1974. On May 30, 1974 a revised sulfur dioxide control strategy and regulations were submitted by the Governor of Ohio, but these were overturned by the Ohio Environmental Board of Review prior to any action by EPA. Finally, the Governor of Ohio formally withdrew the proposed sulfur dioxide regulations on July 16, 1975.

In such situations, the Clean Air Act directs the Administrator of EPA to propose and subsequently promulgate a substitute implementation plan. Pursuant to this directive the U.S. EPA on November 10, 1975 proposed regulations for the control of sulfur dioxide emissions in the State of Ohio (40 FR 52410). These proposed regulations were based, in part, upon the results of a modeling study performed by Region V of EPA and reported in a 2-volume Technical Support Document[1]*. It is understood that the Ohio Confirmation Inventory used for the current investigation also constituted the data bank for the modeling study.

The EPA Administrator is also directed to consider before promulgation of such standards not only the technical aspects of achieving the proposed standards but also their inflationary impacts. Pursuant to this requirement,

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* References at end of report.

the general objective of the investigation described in this report was to assess the plant costs of meeting these proposed emission standards (considering several alternatives), from which the inflationary impacts could be evaluated by another contractor.

OBJECTIVES

The principal objective of the program was to organize and compile the available data on Ohio nonutility SO_2 emitters, and to provide cost estimates from which the inflationary impact on Ohio of the proposed SO_2 emission regulations could be determined. This overall objective broke down into several subtasks:

1) Compile, review and verify the data base
2) Prepare preliminary summary tables of fuel usage, capacity, industry and county for initial use by the economics contractor
3) Develop cost algorithms for SO_2 control for nonutility boilers by flue gas desulfurization (FGD) including sludge handling and disposal
4) Develop costs and energy data for control of SO_2 emissions from industrial processes
5) Prepare a tape with the results for use by the economics contractor.

PROPOSED STANDARDS

The proposed standards, as presented in 40 FR 52410, for control of SO_2 emissions in Ohio fall into two categories; (a) fossil fuel-fired steam generating units, and (b) process sources. They parallel, in general, the earlier SO_2 regulations promulgated February 1, 1974, by the Ohio EPA[2], but employ somewhat different definitions of sources, and set differing limits.

Fuel Combustion

In the earlier Ohio EPA regulations, fuel combustion was considered to include those sources..."in which fuel is burned primarily to produce heat or power by indirect heat transfer and in which the sulfur dioxide emission is largely due to the sulfur content of the fuel burned." This definition includes such sources as petroleum refinery process heaters, a fairly populous category of process sources in Ohio. However, in the proposed Federal regulations, the narrower definition of "fossil fuel-fired steam generating unit" is used. Under this definition all indirectly fired non-steam generating units are excluded, and compliance is necessarily based on the general process equation(*). Determination of compliance is uncertain for such sources since process weight rates are almost invariably unavailable for these types of sources.

In both the earlier Ohio EPA regulations and the newly-proposed U.S. EPA regulations for control of SO_2 emissions from fuel combustion, the allowable limits differ depending on the county in which the source is located. In the proposed regulations, allowable emissions vary between 0.6 lb SO_2/MM Btu (for two counties) up to no limits (for 34 rural, non-industrial counties).** The regulations are summarized in Table 1. The variations in emission limits with geographic locations are illustrated by the Ohio county map in Figure 1.

It should be noted that there are no non-utility boilers above 1500 MM Btu/hour listed in the Ohio inventory, so that the highest class includes only utility boilers.

Process Sources

Emissions of SO_2 from existing process sources are governed by several specific proposed regulations, plus a general regulation based on process weight rate. These regulations are not county-dependent, except that there are no sulfur dioxide emission or hydrogen sulfide combustion limitations for the "no-limit" counties discussed above.

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* This interpretation was confirmed by Region V.

** However, it should be noted that sources in these counties will still be subject to State new source review requirements, and Federal new source performance standards, and non-degradation requirements.

TABLE 1. ALLOWABLE EMISSIONS FOR FOSSIL FUEL-FIRED STEAM GENERATORS

County	Ohio I.D.	All Sizes	Lbs $SO_2/10^6$ Btu/Hour Heat Input		
			10^6 Btu/Hour		
			<22.5	22.5-3000	>3000
Adams	07-01	2.0			
Allen	03-02	1.6			
Ashland	02-03	N			
Ashtabula	02-04	1.2			
Athens	06-05	3.2			
Auglaize	03-06	4.8			
Belmont	17-07		6.0	(b)	1.2
Brown	01-08	N			
Butler	18-01		2.4(c)	(d)	1.2(c)
Carroll	02-10	N			
Champaign	05-11	N			
Clark	08-12	5.2			
Clermont	18-13	0.6			
Clinton	05-14	N			
Columbiana	17-15	4.4			
Coshocton	02-16	4.0			
Crawford	03-10	6.8			
Cuyahoga	13-18		6.0	(b)	1.2
Darke	08-19	N			
Defiance	03-20	N			
Delaware	03-21	6.0			
Erie	03-22	4.0			
Fairfield	01-23	5.6			
Fayette	01-24	N			
Franklin	01-25	2.4			
Fulton	03-26	N			
Gallia	06-27	4.4			
Geauga	02-28	N			
Greene	08-29	1.2			
Guernsey	01-30	N			
Hamilton	14-31		2.4(c)	(d)	1.2(c)
Hancock	03-32	3.2			
Hardin	03-33	N			
Harrison	02-34	N			
Henry	03-35	3.6			
Highland	01-36	N			
Hocking	01-37	5.6			
Holmes	02-38	N			
Huron	03-39	4.8			
Jackson	06-40	N			
Jefferson	17-41		6.0	(b)	1.2
Knox	03-42	4.0			

* The Ohio Regulatory Agency Code followed by the country code.

TABLE 1. (Continued)

County	Ohio I.D.	All Sizes	Lbs $SO_2/10^6$ Btu/Hour Heat Input		
			10^6 Btu/Hour		
			<22.5	22.5-3000	>3000
Lake	02-43		6.0	(b)	1.2
Lawrence	07-44	4.4			
Licking	01-45	3.2			
Logan	05-46	N			
Lorain	19-47		6.0	(b)	1.2
Lucas	04-48		6.0	(b)	1.2
Madison	01-49	N			
Mahoning	02-50		6.0	(b)	1.2
Marion	03-51	4.0			
Medina	16-52	N			
Meigs	06-53	N(a)			
Mercer	03-54	5.6			
Miami	08-55	2.8			
Monroe	17-56	N			
Montgomery	08-57		3.0(c)	(e)	1.6(c)
Morgan	01-58	2.4			
Morrow	03-59	N			
Muskingum	01-60	0.6			
Noble	01-61	N			
Ottawa	03-62	1.6			
Paulding	03-63	N			
Perry	01-64	N			
Pickaway	01-65	6.0			
Pike	01-66	5.2			
Portage	16-67	5.6			
Preble	08-68	N			
Putnam	03-69	N			
Richland	03-70	1.2			
Ross	01-71	5.2			
Sandusky	03-72	N(a)			
Scioto	07-73	4.0			
Seneca	03-74	3.2			
Shelby	05-75	N			
Stark	15-76	1.6			
Summit	16-77		6.0	(b)	1.2
Truball	02-78		6.0	(b)	1.2
Tuscarawas	02-79	3.2			
Union	03-80	N			
Van Wert	03-81	N			

TABLE 1. (Continued)

County	Ohio I.D.	All Sizes	LBs $SO_2/10^6$ Btu/Hour Heat Input		
			10^6 Btu/Hour		
			<22.5	22.5-3000	>3000
Vinton	06-82	3.6			
Warren	18-83	N			
Washington	06-84	2.4			
Wayne	02-85	2.8			
Williams	03-86	N			
Wood	03-87	1.6			
Wyandot	03-88	N			

Notes:

N = No limits set

(a) Counties omitted from listing in 40 FR 52410; the Technical Support Document indicates these are no-limit counties

(b) $E = 16.71\ Q_m^{-0.329}$

(c) Size groups for this row are different than column headings: groups have values < 50; 50-1500; and > 1500 million Btu/hour

(d) $E = 5.33\ Q_m^{-0.204}$

(e) $E = 6.18 Q_m^{-0.135}$

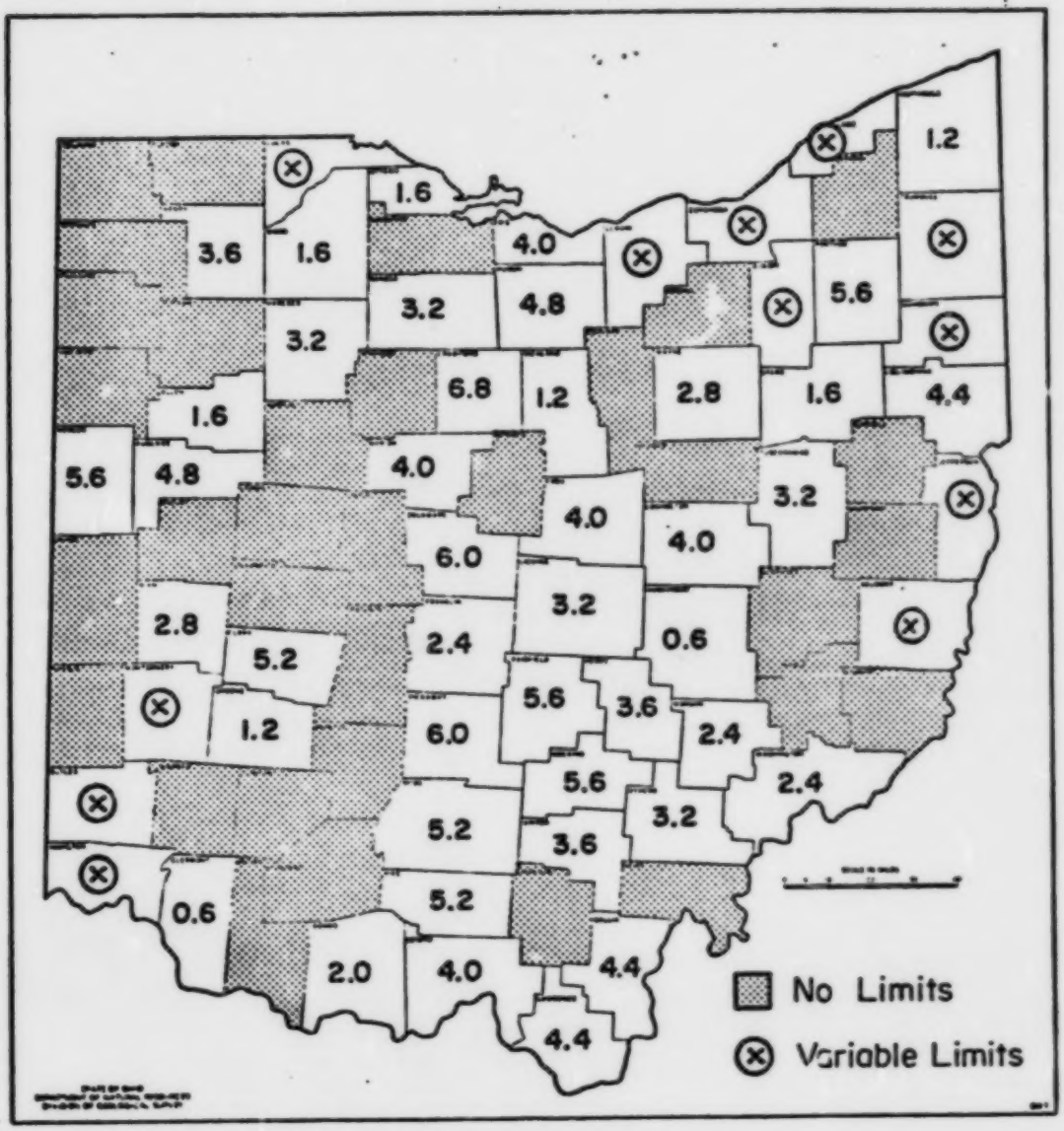

FIGURE 1. ALLOWABLE SO_2 EMISSIONS FOR OHIO COUNTIES

The general process emission regulation limits SO_2 emissions as follows:

$$E = 19.5\ P^{0.67}$$

where P = tons of process weight per hour and E is allowable emission, lbs/hour.

Emissions from combustion of petroleum refinery fuels are regulated by a limit of total sulfur content of 50 grains (as hydrogen sulfide) per 100 dry standard cubic feet of fossil fuel combusted. Additionally, emissions from a sulfur recovery plant are limited to 0.01 lbs SO_2/lb of sulfur processed (= 99.5 percent recovery), which would govern the design and operation of Claus plants. However, a "sulfur recovery plant" does not include facilities where sulfur recovery is utilized primarily as a means of preventing emissions of sulfur dioxide or other sulfur compounds, which could exempt petroleum refinery sulfur recovery units.

Sulfuric acid plant emissions are limited to 6.5 lbs SO_2/ton of 100 percent H_2SO_4 produced (except that sulfuric acid plants operated in conjunction with the desulfurization of by-product coke oven gas are exempted). Also exempted are facilities where conversion to sulfuric acid is utilized primarily as a means of preventing emissions to the atmosphere of sulfur dioxide or other sulfur compounds.

The legal ambiguity relative to the "primary" purpose of a sulfur recovery or sulfuric acid facility is not resolvable within the context of the present study as no data were available on this aspect. For purposes of this study, it was assumed that proposed regulations for sulfur recovery plants would be applicable.

Processes operated in conjunction with the desulfurization of coke oven gas are specifically exempted from the above regulations governing sulfur recovery plants. However, the 50 grains of H_2S/100 dscf limitation noted above for petroleum refinery fuel combustion is also applied to the combustion of coke oven gas.

Emissions of SO_2 from primary zinc smelters are limited to

$$Y = 0.564\ X^{0.85}$$

Where X is the total sulfur feed per hour, and Y is the allowable sulfur dioxide emission rate in lbs/hr.

ANALYSIS OF THE OHIO SO_2 EMISSIONS INVENTORY

Procedure

The major areas of the study performed by Battelle include:

(1). The processing of the provided Emissions Inventory tape to produce the format required by the economic analysis, including the results of item 2 to 4, below

(2) The analysis of costs for the control of SO_2 emissions from Ohio process sources

(3) The analysis of costs for the control of SO_2 from the combustion of fossil fuel in steam boilers

(4) The determination of growth for which costs of control would be attributable to the EPA proposed regulations.

Each of these areas is discussed in detail in the following sections.

The industrial point source SO_2 inventory was provided to Battelle by the Ohio Environmental Protection Agency at about the beginning of the contract in February, 1976. This inventory is substantially the one that was provided to Region V EPA for the purposes of their point source modeling. However, this inventory includes a number of sources added since Region V's efforts. In addition, the inventory includes point sources which emit 10 tons or more per year of SO_2, whereas the inventory considered by Region V analyzed as point sources only those sources emitting more than 100 tons per year of SO_2.

The first step in the study was to determine which of those sources in the inventory should be treated for the analysis of costs. Battelle obtained from the Ohio EPA a publication examining the technical justification for emission-based cutoff of insignificant sources from the permitting process[3]. This publication is based upon a boiler inventory derived from the emissions inventory system of the Ohio EPA and a small boiler data file from the Ohio Energy Emergency Commission. By assuming that the costs of control were related to the boiler emission rate to some power it was possible to derive total costs of control as a function of size.

This was done for two separate powers. The first power used was 0.6 which should approximate capital costs. The second power used was 1.0 which should approximate operating and maintenance costs. The total accumulative cost of control as a function of boiler emission rate for these two powers is presented in Figure 2. It is seen in this figure that a cutoff of 25 tons a year of SO_2 emission results in underestimation of capital costs by about 5 percent and operating and maintenance by about 1 percent. Likewise a cutoff of 100 tons produces about a 10 percent underestimation of total capital costs. Based on this analysis, it was decided to use the entire emission inventory as provided by the Ohio EPA in the cost estimation procedures.

The inventory contained approximately 1800 sources. Approximately 2/3 of these were combustion sources and 1/3 were process sources. Of the total, approximately 1/3 represent emission sources under 25 tons per year.

As is typical of any large and relatively new data base, the emission inventory contains many significant errors. These errors included misestimations or absent entries for stack flow rate, annual and maximum hourly consumption rate of fuels, the heat value of the fuel, and the size. A typical error was to use the heating value based on the wrong unit. Thus coal might be represented as having a heating value of 13,000, which is the correct value for Btu's per pound, whereas the correct number should have been in units of 26×10^6 Btu's per ton. Thus the total heat content represented by that plant would be over estimated by a factor of 2000. Many of these errors could be picked up and corrected readily by eyeball, but it was estimated that approximately 1/2 of the sources listed contained errors of this magnitude. Since it was not within the scope of Battelle's contract to perform an emissions inventory, the approach taken was to provide for some automatic correction of sources by computer analysis rather than by an engineering assessment on a source by source basis.

Battelle began the correction procedure by looking at the boiler design rate within the emission inventory and correcting those which violated engineering judgement. Next, the entire data base was examined, entry by by entry, to provide default values for heat content and for operating hours where the numbers provided in the inventory seemed incorrect. After these two numbers were corrected it became possible to correct the annual fuel consumption rate

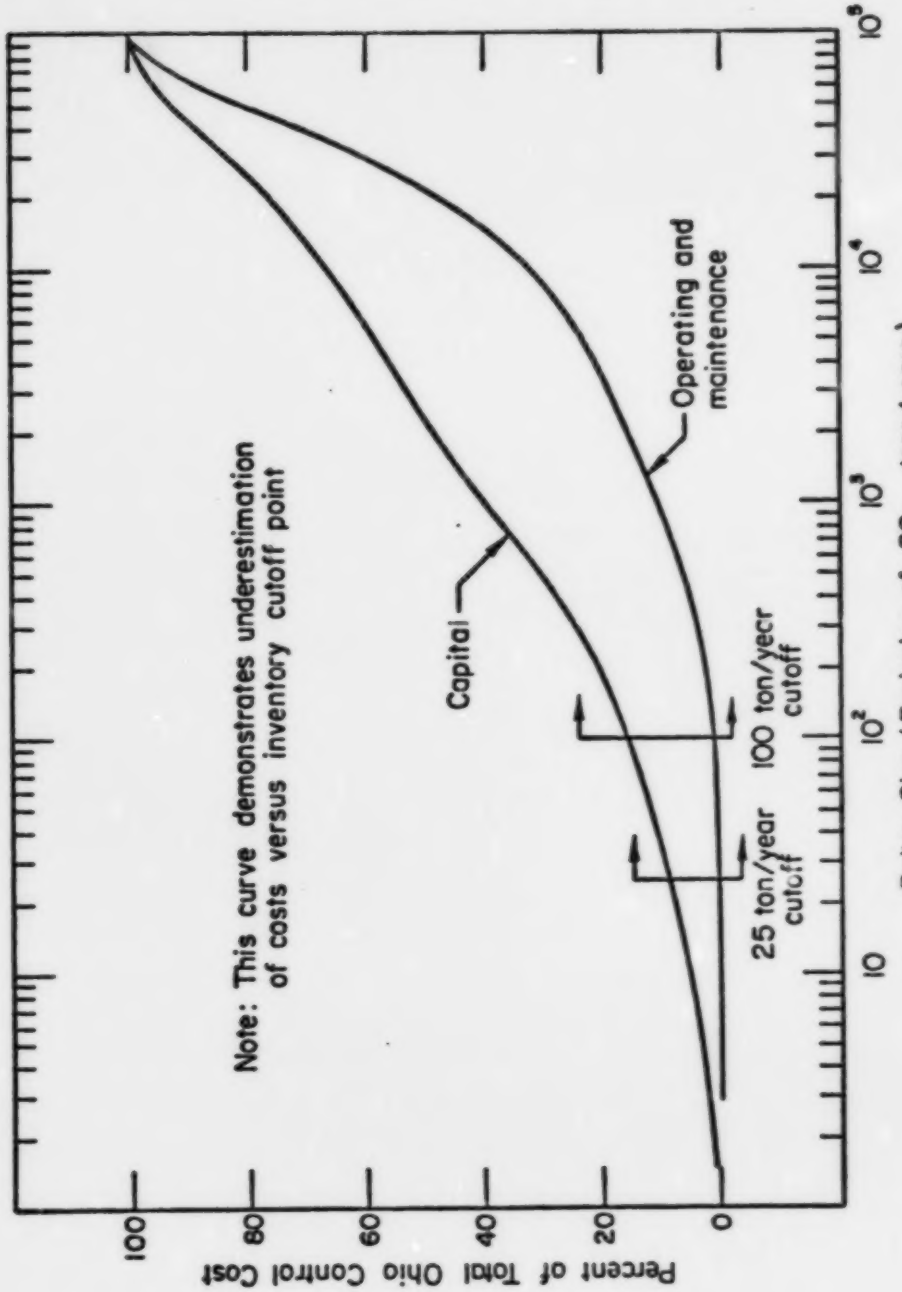

FIGURE 2. ESTIMATED CUMULATIVE CAPITAL AND OPERATING COSTS FOR OHIO BOILERS AS A FUNCTION OF BOILER SIZE

and the maximum hourly consumption rate where these numbers seemed significantly in disagreement with the boiler design rate, the operating schedule, and the heat value of the fuel. The algorithms designed for these automatic changes had to be flexible and sensitive enough to pick up errors where there were truly errors and yet not change or correct data that were somewhat outside of normal bounds. The data base resulting from these manipulations contains information which may not necessarily be correct for all sources, but certainly all of the data are within a reasonable ballpark of their intended values. Summary data from the resulting data bank are presented in Tables 2 through 4.

As is discussed later on in this report, Battelle was requested to provide costs of control for both fuel combustion sources and process sources. In the examination of the data base it was found that the process sources consisted of:

(a) Process sources which burn fuel as a part of the process
(b) Process sources which emit SO_2 as a result of a chemical nature of the process
(c) Process sources which emit sulfur from the combustion of the fuel gases containing hydrogen sulfide.

Fuel gases are derived from the processing of coke or petroleum. The methodology described later in this report was used to estimate cost and energy requirements of processes to come into compliance with the proposed Federal EPA SO_2 emission standards. Each noncombustion process source for which control technologies exist to meet SO_2 standards is provided with one alternative for control. In some of these cases the provided control technology is not required since the current emission rate does not exceed the applicable proposed standards. However, for the purpose of completeness, the control technologies for complying sources were costed. Only one alternative was costed as, for the sources examined, the proposed regulation dictated a level of technology which was relatively insensitive to small changes in regulations. A cost sensitivity was provided by allowing this technology, scaled down in size, to be applied to a fraction of the stream to be controlled.

TABLE 2. TOTAL OHIO NON-UTILITY FUEL CONSUMPTION BY FUEL TYPE AND USAGE

Fuel Type	Fuel		MM Btu/Yr	
	Quantity, MSCC/Yr	Unit	Boilers	Processes
1.Anthracite coal	572523.	tons/yr	1035700.	0.
2.Bituminous coal	71515933.	" "	269102064	5140651.
3.Lignite	96880.	" "	1937600.	0.
4.Residual Oil	535684.	M gal/yr	58803609.	16800.
5.Distilliate oil	466095.	" " "	45435119.	293853.
6.Natural gas	203652.	M cuft/yr	192172087.	301088.
7.Process gas	606907.	" " "	75100827.	7138069.
8.Misc.	641660.	Misc.	2548302.	134592.

TABLE 3. TOTAL HEAT OUTPUT OF NON-UTILITY COAL-FIRED HEATERS/BOILERS BY SIZE

Size, Btu/hr	Heat Output, MM Btu/yr	
	Boilers	Processes
0-3K	10871.	0.
3K-10K	66637.	22488.
10K-30K	397867.	0.
30K-100K	4871063.	979896.
100K-300K	34404048.	2170251.
300K-1M	87307870.	758016.
1M-3M	97841594.	1210000.
3M-10M	47175414.	0.
10M-30M	0.	0.
30M-UP	0.	0.

TABLE ... TOTAL NON-UTILITY COAL CONSUMPTION BY SULFUR CLASS

Sulfur Class, Percent	Consumption, Tons/yr	
	Boilers	Processes
0-.6	13677.	0.
.6-.8	1029286.	14010.
.8-1.3	2358705.	45358.
1.3-1.8	130686.	19880.
1.8-3.4	5316110.	132392.
3.4-5	2309275.	313.
5.-UP	92348.	0.

Other control technologies could be proposed as alternatives to those Battelle provided, providing for compliance to different levels of allowable emission. However, examination of alternatives suggested by the EPA proposed regulations shows that the differences are quite significant. For example, the current proposed SO_2 regulation for sulfuric acid plants is six pounds per ton of sulfuric acid, whereas the suggested alternative to this regulation is 27 pounds per ton of sulfuric acid. Thus there are significant differences in regulations proposed in the Federal Register, and the alternatives suggested by EPA. As a result a variety of control options and control technologies for each process source were not provided, on the basis that if the proposed regulations were weakened to one of the alternative forms the plants affected would be in compliance without further treatment. Again, for example, all of the current sulfuric acid production plants in the State of Ohio are in compliance with the suggested alternative regulation of 27 pounds of SO_2 per ton of sulfuric acid.

Control alternatives for fuel combustion both for the generation of steam and process sources can be estimated externally through the use of the methodology developed and presented later in this report. These alternatives include, in general; (a) a control technology representing application of flue gas desulfurization to the entire unit or stack exhaust stream; (b) control technology representing an application of flue gas desulfurization

to a fraction less than 75 percent of the exhaust stream (the fraction being determined by the exact control regulation requirements); and (c) a control technology representing a fuel switch from high-sulfur coal or oil to low-sulfur coal or oil. In the event the low-sulfur fuel switch occurs where particulates are controlled by a electrostatic precipitator, it may be necessary to provide an extra degree of particulate control. A methodology is provided for this purpose (there are eight boilers/processes subject to this condition).

The emissions inventory was combined with the process control technology data and was used to produce a data tape corresponding to the requirements* proposed by another EPA contractor, Energy and Environmental Analysis Inc. (EEA). Basically, within this tape the sources are grouped together by plant. Within the plant units are grouped together by stack (sometimes there are common units on a stack). Somewhere between 50 and 100 card images were used to represent each plant. Region V EPA estimates of growth were combined with these data to produce a duplicate record on the tape for each plant to represent growth in place. The data tape, produced according to EEA specifications, the algorithms necessary to cost fuel combustion sources, and process cost data were provided to EEA in the format of their choosing. The format of the presented information allows for ready alteration in the event the proposed regulations are altered.

PROCESS SOURCES

Process sources on the data tape provided by the Ohio EPA can be categorized into three major areas:

(a) Sources which emit SO_2 due to the combustion of fossil fuel

(b) Sources which emit SO_2 due to chemical processing

(c) Sources which emit SO_2 due to the combustion of fuel gases containing hydrogen sulfide.

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* An outline of the tape contents is presented in Appendix A.

Each of these categories of sources was handled in a different manner.

The industries using byproduct gases, for example, were treated by using a whole-plant desulfurization process. The processing of petroleum and coke generates large volumes of combustible byproduct gas containing traces of hydrogen sulfide. To avoid the odor of H_2S and/or to utilize the heat value of this gas, the gas stream is burned in process heaters or is flared, with the subsequent oxidation of the sulfur to SO_2.

The best, least expensive approach to bringing all of the fuel gas streams within a plant into compliance is to provide for amine stripping of the individual gas streams and a common, central amine regenerator. Since these costs are not allocatable to individual units, the cost, etc., for these plants are aggregated for the entire plant. Further details are provided in the following subsections on Coke Oven Plants and Petroleum Refineries.

The industries which combust fuel in the processes are treated by the same methodology used for fuel combustion for the generation of steam.* Remaining processes which emit SO_2 because of the chemical nature of the process were each individually analyzed by experts in the field to produce for each plant the capital costs, operating costs, etc. required for the economic analysis.

Petroleum Refineries

The following general observations are made about the facilities discussed in this analysis:

1. Oil and Gas Journal (April 7, 1975), no longer lists the Chevron Asphalt Plant in Cincinnati. In 1974 (OGJ, April 1, 1974) it was listed as shut down but operable. It has been omitted from the calculations.
2. The requirement of no fuel gas of more than 50 grains H_2S per 100 dscf (about 0.075 percent by volume or 0.17 percent sulfur by weight) was considered to apply to both fuel for boilers and process heaters. Clean up requires amine scrubbing, stripping, a Claus sulfur recovery unit and a tail gas clean up so that 99.5 percent of the sulfur is

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* It should be pointed out that the general process weight rate regulation which applies to processes is in general more stringent than the fuel combustion regulation which is applied to fuel combustion for the generation of steam.

removed from the Claus plant input. The regulations are ambiguous as to whether tail gas clean up is required. If the Claus plant is primarily for abatement, no tail gas clean up is required; however, only coke oven gas is specified as exempt. Since New Source Performance Standards for Claus plants are under consideration by EPA, the problem is probably serious and the cost of the clean up of tail gas from both old and new Claus plants was therefore included. The costs were calculated on the basis of the whole refinery, not on a unit-by-unit basis.

Amine Scrubbing and Stripping Costs. From data on a new 150,000 (B/D) Barrel/Day refinery and assuming a 0.7 scale factor capital costs were estimated as:

$$\text{Cost} = \$749\ (\text{B/D capacity})^{0.7}.$$

There is some uncertainty when this is applied to small refineries but it was the best approach available. The cost of the retrofit in old refineries was assumed equal to that in grass roots installations.* Operating and maintenance costs were assumed to be 7 percent of capital plus $36.66 per long ton of sulfur input to the Claus unit. Energy consumed was taken to be 15.6 MMBtu per long ton S to the Claus plant. The scrubbing was assumed 99.9 percent effective. Data are based on manufacturers' specifications and information from a non-proprietary study by BCL.[26]

Claus Plant. Two two-stage Clause plants each of 60 percent of needed capacity were assumed except where there was an existing Claus plant that needed supplementation. Capital costs for each unit were calculated from the equation

$$\text{Cost} = \$1.50 \times 10^5\ (\text{long tons S/day})^{0.627}$$

Operating costs were 5 percent of capital plus $2.78 per long ton of sulfur. A credit of $20 per long ton (a long term expected price) and $1.41 steam credit per long ton sulfur were applied. Energy credits were 284,000 Btu per long ton sulfur. Efficiency is about 94.5 percent.

* Numbers and approximations in this study are justified in Reference 26.

Tail Gas Clean Up. Of the available technologies, only the Chiyoda, Davy Powergas, Beavon and Shell processes give the required degree of abdtement. Since details on the Shell Claus Off-gas Treatment (SCOT) process were available from the developer, these were used after escalation to January 1, 1975, costs, using the Nelson Refinery Cost Index.

Capital costs were calculated from the equation

$$\text{Cost} = \$1.02 \times 10^5 \text{ (Claus plant capacity in long tons per day)}^{0.584}$$

Operating costs, assuming about 2/3 utilization, were $2.76 per ton S input to the Claus plant. Energy consumption is 1.96 MMBtu per ton at the same operating level. Efficiency of clean up equipment was assumed to be 99.5 percent overall (Claus plus a Scot) but the system is capable of 99.9 percent removal.

Boilers. The SO_2 emissions for boilers were calculated to determine if the fuel was in compliance. However, it was assured that fuel gas must meet the 50 grain per 100 scf limit, with costs for fuel gas sulfur abatement calculated as provided by amine stripping/Claus plant.tail gas cleanup. Costs for other boiler fuels are provided by the fuel combustion algorithms descrived in the section on fossil fuel combustion.

Process Effluents. The equation $E = 19.5\ P^{0.67}$ was applied to the fluid catalytic cracking units and, where data were available, to asphalt plants. The allowable was always found to be about 10 times actual emissions. (This emission shows up as SO_2 from the CO boiler, if any, or the FCC catalyst regenerator, as well as in the flue gas of the FCC heaters).

For other units, process sulfur is contained in the product or the refinery gas system. Each unit was checked, where possible, to be sure that its fuel met all boiler fuel* requirements. However, with the data provided, throughput of most units, and even the function of some of the units, was not available for calculation using the process effluent equation. It was felt that if FCC units, which involve considerable heating, are in compliance, all units would be, the FCC units only were checked on facilities where other data were unavailable.

Iron and Steel Plants

Coke Oven Plants

For three coke oven plants, data sheets were completely or partially missing. In those cases, as shown in Table 5, data on the coal capacity of the plants were used as the annual coal charged.

Coke ovens generate 11,600 cubic feet of gas per net ton of coal charged.[4] The capital cost of a Claus desulfurization process for retrofit on coke ovens is given by the equation

$$\chi = 0.71y^{0.56}$$

where χ is million dollars and y is million cubic feet of coke oven gas per day.[5] Installation of the desulfurization process in a new plant was assumed to be 75 percent of the cost of retrofit.

Data on the operating cost of the Claus process were generated by three steel plants and reestimated by the Battelle Columbus Laboratories.[5] A best-fitting straight line through the plot of the average of their operating costs for three plants had the form of

$$\chi = \frac{y-0.46}{72.37}$$

where χ is million dollars and y is million cubic feet of coke oven gas per day. The operating cost was assumed to be the same for a new plant as for retrofit.

Steam for operating the Claus process for the three plants fitted a straight line having the form of

$$\chi = 0.0917y$$

where χ is million pounds of steam and y is million cubic feet of coke oven gas per day.[5] The energy equivalent of one pound of steam raised in a steel plant is 1000 Btu.[6]

TABLE 5. COKE OVEN PLANTS IN OHIO

Company	Ohio I.D. Number	Coal Charged, T/YR	Annual Coke-Oven Gas, 10^6 CF	Glaus Desulfurization Process						Total Energy, 10^6 Btu/yr	Life, yr	Input Product Weight Rate, T/hr	Uncontrolled Emission, T/yr	Allowable Emission, T/yr	Reservoir Emission, T/yr
				Capital Cost, 10^6 $	Operating Cost, 10^6 $	Steam 10^6 lb/yr	Steam 10^6 Btu/yr	Electric Energy 10^6 kwh/yr	Electric Energy 10^6 Btu/yr						
Furnace															
Armco Steel Corp. Middletown Plant	1809000023 Three stacking	594,776 (a)	6,305	3.3 Retro 2.0 New	0.23 Retro 0.23 New	31.90	31,900	1.39	10,031	60,331	16	68.00	2,044 (c)	423	343
Armco Steel Corp. Middletown Works	1809010056	317,360	5,406	3.2 Retro 2.4 New	0.20 Retro 0.20 New	45.30	45,300	1.30	14,534	59,834	16	59.34	1,778 (c)	360	256
Empire Detroit Steel Div. Detroit Steel Corp.	0775810004	488,000	4,340	2.6 Retro 2.1 New	0.13 Retro 0.13 New	31.00	31,000	1.06	11,165	45,965	16	45.79	1,993	305	140
Interlake, Inc.	0144000397	424,000	4,494	2.9 Retro 2.2 New	0.16 Retro 0.16 New	36.90	36,900	1.13	11,839	48,739	16	48.53	996	301	42
Republic Steel Corp., Cleveland	1351400010A3	1,970,000	20,883	6.9 Retro 5.2 New	0.79 Retro 0.79 New	172.30	172,300	5.36	56,340	237,440	16	225.52	6,043	1,400	425
Republic Steel Corp., Massillon	1371130006	236,000	2,502	2.1 Retro 1.6 New	0.09 Retro 0.09 New	20.70	20,700	0.63	6,641	27,341	16	27.01	472	168	30
Republic Steel Corp., Warren	0278100137	488,000	5,000	3.1 Retro 2.3 New	0.19 Retro 0.19 New	42.00	42,000	1.28	13,475	55,475	16	54.94	1,980	342	133
Republic Steel Corp., Youngstown	0250130104	1,109,092	11,763	5.0 Retro 3.8 New	0.44 Retro 0.44 New	99.90	99,900	3.04	32,069	131,969	16	127.09	3,871	790	301
U.S. Steel Corp., Lorain Cuyahoga Works	Seven stacking	1,430,000 (a)	17,362	6.2 Retro 4.7 New	0.65 Retro 0.65 New	163.10	163,100	4.37	45,911	209,011	16	207.30	5,039 (c)	1,160	744
Youngstown Sheet & Tube Co. Campbell Works	0250000241	1,354,000	13,600	5.0 Retro	0.31 Retro	112.000	112,000	3.43	35,990	148,190	16	146.97	6,488	914	469
Beehive															
Diamond Shamrock Chemical Co.	Missing (23 Ovens)	354,000 (b)	3,870	3.2 Retro 1.7 New	0.10 Retro 0.10 New	22.30	22,300	0.69	7,219	29,719	16	30.45	1,915 (c)	139	134
Ironton Coke Plant, Allied Chem. Corp.	0744010004	1,098,117	10,686	4.7 Retro 3.3 New	0.48 Retro 0.48 New	88.30	88,300	2.70	28,350	116,350	16	113.40	7,297	717	310
Total				48.0 Retro 36.1 New	3.91 Retro 3.91 New										

(a) Capacity from Bonnevier, "Columbiana—The Struggling Phoenix", Institute for Iron and Steel Studies, IV-16, October, 1973.

(b) Capacity from Battelle Columbus Laboratories' files.

(c) Based on average emission per T coal for seven furnace plants listed in table.

(d) Emission data were incorrect. This value is based on average emission per T coal for seven furnace plants listed in this table.

(e) Based on emission per T coal at the Ironton Coke Plant of Allied Chemical Corp.

Values for the input product weight rate and the summation of uncontrolled emission of sulfur dioxide were obtained from the data sheets. In those cases where the uncontrolled emission was missing or obviously in error, a value was used that was based on the average emission per net ton of coal charged in the other coke plants.

The allowable emission of sulfur dioxide was calculated on the basis of 50 grains of hydrogen sulfide per 100 standard cubic feet of coke-oven gas.[7] The Claus process removed 93 percent of the hydrogen sulfide from the coke-oven gas.[8]

All of the coke plants are well within compliance with respect to emission of sulfur dioxide when the Claus desulfurization process is used, even though the emission per net ton of coal charged by the merchant plants was twice that of the captive plants.

Facilities Using Coke Oven gas. In the integrated steel plants, coke oven gas (500 Btu per cubic foot), blast-furnace gas (90 Btu per cubic foot), and natural gas (1000 Btu per cubic foot) are blended to obtain a thermal value appropriate for firing a given facility. The objective is to use as much of the coke-oven gas and blast-furnace gas as possible.

Under "Ohio I.D. No.", in Table 6, coke-oven batteries are identified for which data sheets were available as well as those for which sheets were missing. Also identified are those facilities that use coke-oven gas. Pertinent data were missing or obviously in error in the sheets for some of the facilities. Values were deduced in those instances to permit assessment of whether or not the facility was in compliance with regard to emission of sulfur dioxide.

When the Claus process is used for desulfurizing the coke-oven gas at the coke ovens, all of the facilities using coke-oven gas were in compliance.

TABLE 6. LISTING OF COKE OVENS AND PROCESSING UNITS USING COKE-OVEN GAS

Ohio I.D. Number	Type of Unit	Company
1809080023P005	Coke oven	Armco Steel Corp., Hamilton Plant, New Miami
Missing	Coke oven	Armco Steel Corp., Hamilton Plant, New Miami
Missing	Coke oven	Armco Steel Corp., Hamilton Plant, New Miami
Missing	Coke oven	Armco Steel Corp., Hamilton Plant, New Miami
180901006P013	Coke oven	Armco Steel Corp., Middletown Works, Middletown
Missing	Coke oven	Diamond Shamrock Chemical Co., Painesville
07730100 4B001	Coke oven	Empire Detroit Steel Division, Detroit Steel Corp., New Boston
0773010004P007[a]	Soaking pits	Empire Detroit Steel Division, Detroit Steel Corp., New Boston
0448010397P003	Coke oven	Interlake, Inc., Toledo
0744010004P003	Coke oven	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004P004	Coke oven	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004P008	Coke oven	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004P001	Coke oven gas bleeder	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004P002[b]	Coke gas desulfurizer	Ironton Coke Plant, Allied Chemical Corp., Ironton

TABLE 6. (Continued)

Ohio I.D. Number	Type of Unit	Company
0744010004P005[c]	Ammonia purification	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004B002	Coke oven flue	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004B003	Coke oven flue	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010004B004	Coke oven flue	Ironton Coke Plant, Allied Chemical Corp., Ironton
0744010008B003[d]	Annealing oven	Ironton Malleable Division, Dayton Malleable Iron Co., Ironton
1318001613P004	Coke oven	Republic Steel Corp., Cleveland
1318001613P005	Coke oven	Republic Steel Corp., Cleveland
1318001613P034	Coke oven	Republic Steel Corp., Cleveland
1318001613P036	Coke oven	Republic Steel Corp., Cleveland
1318001613P037	Coke oven	Republic Steel Corp., Cleveland
1318001613P015	Soaking pits	Republic Steel Corp., Cleveland
1318001613P016	Soaking pits	Republic Steel Corp., Cleveland
1318001613P017	Soaking pits	Republic Steel Corp., Cleveland
1318001613P018	Soaking pits	Republic Steel Corp., Cleveland
1318001613P019	Soaking pits	Republic Steel Corp., Cleveland
1318001613P020	Soaking pits	Republic Steel Corp., Cleveland
1318001613P021	Soaking pits	Republic Steel Corp., Cleveland
1318001613P022	Soaking pits	Republic Steel Corp., Cleveland
1318001613P023	Soaking pits	Republic Steel Corp., Cleveland

TABLE 6. (Continued)

Ohio I.D. Number	Type of Unit	Company
1318001613P024	Soaking pits	Republic Steel Corp., Cleveland
1318001613P025	Soaking pits	Republic Steel Corp., Cleveland
1318001613P026	Soaking pits	Republic Steel Corp., Cleveland
1318001613P027	Soaking pits	Republic Steel Corp., Cleveland
1318001613P012[e]	Bar-heating furnace	Republic Steel Corp., Cleveland
1318001613P013[f]	10-bar mill	Republic Steel Corp., Cleveland
1318001613P039[g]	98" mill	Republic Steel Corp., Cleveland
1318001613P040[g]	98" mill	Republic Steel Corp., Cleveland
1318001613P041[g]	98" mill	Republic Steel Corp., Cleveland
1318001613P042[g]	98" mill	Republic Steel Corp., Cleveland
1318001613P043[g]	98" mill	Republic Steel Corp., Cleveland
1318001613P046	84" mill	Republic Steel Corp., Clebeland
1318001613P047[h]	84" mill	Republic Steel Corp., Cleveland
1318001613P048	84" mill	Republic Steel Corp., Cleveland
1576130696P028	Coke oven	Republic Steel Corp., Massilon
0278080337P003	Coke oven	Republic Steel Corp., Warren Township
0278080337P004	Coke oven	Republic Steel Corp., Warren Township
0278080235P001	Slab-heating furnace	Republic Steel Corp., Warren Township
0278080338P002	Soaking pits	Republic Steel Corp., Howland Township
0278080338P003	Soaking pits	Republic Steel Corp., Howland Township
0278080338P004	Soaking pits	Republic Steel Corp., Howland Township

TABLE 6. (Continued)

Ohio I.D. Number	Type of Unit	Company
0250110464P004	Coke oven	Republic Steel Corp., Youngstown
0250110464P005	Coke oven	Republic Steel Corp., Youngstown
0250110464P006	Coke oven	Republic Steel Corp., Youngstown
0250110464P008	Soaking pits	Republic Steel Corp., Youngstown
0250110464P009	16"-14" bar mill slab furnace	Republic Steel Corp., Youngstown
0250110464P010	Continuous stretch reducing mill furnace	Republic Steel Corp., Youngstown
0250110464P011	Pipe galvanizing line	Republic Steel Corp., Youngstown
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
Missing	Coke oven	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
1741150011B009[(i)]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741150011B010[(i)]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville

TABLE 6. (Continued)

Ohio I.D. Number	Type of Unit	Company
1741150011B011[i]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741150011B012[i]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741150011B013[i]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741150011B014[i]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741150011B015[i]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741150011B016[i]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville N, Steubenville
1741090010B013[j]	Soaking pits	Wheeling-Pittsburgh Steel Steubenville S, Mingo Junction
1741090010B014	Soaking pits	Wheeling-Pittsburgh Steel Steubenville S, Mingo Junction
1741090010B015	Soaking pits	Wheeling-Pittsburgh Steel Steubenville S, Mingo Junction
1741090010B016	Soaking pits	Wheeling-Pittsburgh Steel Steubenville S, Mingo Junction
1741090010B017	Soaking pits	Wheeling-Pittsburgh Steel Steubenville S, Mingo Junction
0250090241P002	Coke oven	Youngstown Sheet & Tube Co., Campbell Works, Struthers
0250090241P026	Coke oven	Youngstown Sheet & Tube Co., Campbell Works, Struthers
0250090241P027	Coke oven	Youngstown Sheet & Tube Co., Campbell Works, Struthers
0250090241P009[k]	Blooming mill furnace	Youngstown Sheet & Tube Co., Campbell Works, Struthers

TABLE 6. (Continued)

Ohic I.D. Number	Type of Unit	Company
0250090241P013	#1 Continuous butt weld mill furnace	Youngstown Sheet & Tube Co., Campbell Works, Struthers
0250090241P014	Pipe galvanizing	Youngstown Sheet & Tube Co., Campbell Works, Struthers
0250090241P018	12" bat mill furnace	Youngstown Sheet & Tube Co., Campbell Works, Struthers

(a) Based on listed uncontrolled emission and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, missing value for coke oven gas used is 4605 x 10^6 CF.

(b) Based on listed uncontrolled emission and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, missing value for coke oven gas used is 656 x 10^6 CF.

(c) Based on listed uncontrolled emission and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, missing value for coke oven gas used is 6711 x 10^6 CF.

(d) Based on listed cubic feet of coke oven gas used and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, the uncontrolled emission is 42 rather than the listed 436.8 NT SO_2.

(e) Based on listed uncontrolled emission and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, missing value for coke oven gas used is 1127 x 10^6 CF.

(f) Based on listed uncontrolled emission and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, missing value for coke oven gas used is 738 x 10^6 CF.

(g) Based on average uncontrolled emission of 0.61 NT $SO_2/10^6$ CF coke oven gas, the uncontrolled emission is 159 NT SO_2 rather than the listed 252.7.

(h) Missing value for coke oven gas used is 154 x 10^6 CF which is the same as for similar mills.

(i) Based on average uncontrolled emission of 0.61 NT $SO_2/10^6$ CF coke oven gas, the uncontrolled emission is 1037 NT SO_2 rather than the listed 123.6.

(j) Uncontrolled emission is incorrect. It is 652.6 NT SO_2 which is the same as for similar batteries.

(k) Based on listed cubic feet of coke oven gas used and average of 0.61 NT $SO_2/10^6$ CF coke oven gas, he uncontrolled emission is 201 rather than the listed 1816 NT SO_2.

Sinter Plants

Under "Ohio I.D. Number", Table 7 identifies those plants for which data sheets were available and those for which sheets were missing. As noted in Table 7, one of the plants had an obvious error in the estimated uncontrolled emission of sulfur dioxide. This was corrected on the basis of annual net tons of sulfur dioxide per annual net ton of sinter produced by the other plants. Then this plant as well as all the other plants listed in Table 7 were in compliance, with the result being that the proposed regulations result in no added cost.

TABLE 7. LISTING OF SINTER PLANTS

Ohio I.D. Number	Company
Missing	Armco Steel Corp., Middletown Works, Middletown
Missing	J & L Steel Corp., Cleveland
Missing	Republic Steel Corp., Cleveland
0278080337P002	Republic Steel Corp., Warren Township
0250110464P007	Republic Steel Corp., Youngstown
Missing	U.S. Steel Corp., Lorain Cuyahoga Works, Lorain
0250110469P035[a]	U.S. Steel Corp., Youngstown
0250090241P001	Youngstown Sheet & Tube Co. Campbell Works, Struthers
0250090241P025	Youngstown Sheet & Tube Co. Campbell Works, Struthers

(a) Uncontrolled emission, based on the other plants, is 1954 net tons per year rather than the listed 2726 net tons per year.

Other Metallurgical Processes

With the exception of three facilities, all other metallurgical processes for which data sheets were available were in compliance with respect to the emission of sulfur dioxide.

Source No. 0125040002P002 refers to a furnace producing zinc oxide. The allowable emission is 157 net tons of sulfur dioxide per year versus the listed estimated uncontrolled emission of 641.3. Based on the listed content of 1 percent sulfur in the charge, the uncontrolled emission is 444 net tons of sulfur dioxide per year. The technology for bringing this facility into compliance will presumably be FGD; costing is covered by the FGD algorithm.

Source No. 1576000475P008 refers to a reverberatory furnace that is used to salvage copper in copper cables. The allowable emission is 9.2 net tons of sulfur dioxide per year versus the listed estimated uncontrolled emission of 25.6. A practical, economical technology is not known for bringing this marginal noncompliance facility into compliance, and thus no costs were estimated for this source.

Source No. 131800022P022 is a reverberatory furnace for "softening" lead and uses the same stack as a lead blast furnace identified as Source No. 131800022P001. Each of these facilities has a listed uncontrolled emission of 89.1 net tons of sulfur dioxide by stack test. Actually this emission probably applies only to the blast furnace because little or no sulfur dioxide is emitted by the reverberatory furnace where the arsenic is oxidized to form a dross which is removed to achieve softened lead. The blast furnace is in compliance because its allowable emission is 155 net tons based on only the tonnage of given metallic charge (the total charge, if known, would make the allowable higher). The reverberatory furnace should also be considered to be in compliance because its actual emission is nil, with no cost attributable to the proposed regulations.

Chemical Sources of SO_2

Primary emitters of SO_2 from chemical processing are sulfuric acid plants and pulp mills. Control for these processes is based, in general, on process changes. The inventory provided to Battelle did not show any pulp mill process sources* that are not in compliance with proposed regulations, although there are sources that are believed to be missing from the inventory.** One Ohio plant produces zinc oxide and is categorized as a smelter with respect to the proposed regulations.

Sulfuric Acid Plants

Sulfuric acid is produced by dry-gas and wet-gas methods. In the dry-gas method, elemental sulfur is burned with dry air in a furnace to produce sulfur dioxide, which is converted catalytically to sulfur trioxide. The sulfur trioxide is absorbed in sulfuric acid solution in a tower to form stronger sulfuric acid by reaction with water. In wet-gas plants, sulfur dioxide is obtained from the combustion of acid sludge or other spent acid, hydrogen sulfide, or smelter off-gas. In these plants, the sulfur-bearing gas is dried and cleaned before introduction to the acid plant. Five dry-gas (sulfur-burning) plants and two wet-gas plants are included in this study. It is noteworthy that one of the wet-gas plants, 04-48-02-0014-P002, has obviously already installed dual-absorption facilities and is in compliance with proposed EPA standards.

Dual absorption was selected as the method of choice for reducing the SO_2 content of tail gas from sulfuric acid plants to acceptable levels. Capital costs for the installation of dual-absorption equipment and annual operating and maintenance costs were calculated from the equation

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* Those sources out of compliance are fuel combustion for the generation of steam, and thus are not true processes.

** The Mead facility in Chillicothe, for example.

$$C = AT^B$$

where C is the cost (capital or O&M), T is the plant capacity in tons 100 percent acid per day, and A and B are constants specific for new and existing wet-gas and dry-gas plants. The constants A and B were updated to January 1, 1975, by the Marshall and Stevens Index from Chemical Engineering from values obtained earlier by Battelle.[9] Table 8 shows the constants used in the current cost calculations. The calculated costs are shown in Table 9.

Energy in the forms of electricity and fuel is required to operate the dual-absorption facilities. These energy requirements are shown in Table 10. The cost of energy is included in Table 9.

Dual absorption generally will not reduce the sulfur dioxide content of tail gases from sulfuric acid plants below about 500 ppm. The tail gas flow rate reported from two of the plants greatly exceeds those from other comparable plants. If the reported rates are correct, even after installation of dual-absorption facilities, the emission of sulfur dioxide would exceed the allowable rate by 29 percent at one dry-gas plant (ID 14-31-35-0817-P001) and by 14 percent at one wet-gas plant (ID 04-48-02-0014-P001). If the reported flow rates are too high, and actual flow rates are in line with those at other sulfuric acid plants, these two plants would also meet EPA standards after installation of dual-absorption facilities. These plants were assumed to have dual absorption technology only, due to the probable discrepancy.

Zinc Smelter

There is one zinc smelter in Ohio (producing zinc oxide). This smelter has a sulfuric acid plant for the purpose of reducing sulfur dioxide emissions. The installation of dual-absorption facilities on the sulfuric acid plant would bring sulfur dioxide emissions into compliance with EPA standards for a manufacturing facility that uses a sulfuric acid plant to control sulfur dioxide emissions.

TABLE 8. VALUES OF A AND B IN THE EQUATION $C=AT^B$ REPRESENTING INVESTMENT AND OPERATING AND MAINTENANCE COSTS FOR EQUIPPING SULFURIC ACID PLANTS WITH DUAL-ABSORPTION FACILITIES

Type of Sulfuric Acid Plant	Capital Costs		Operating and Maintenance Costs (a)	
	A	B	A	B
Dry Gas				
New	15,205	0.59	592	0.84
Existing	51,404	0.60	2,810	0.71
Wet Gas				
New	32,801	0.58	1,388	0.74
Existing	97,283	0.61	6,839	0.64

(a) Operating and maintenance costs include operating labor, electricity, cooling water, fuel oil, maintenance, taxes, insurance, and credit for additional sulfuric acid obtained from operation of the dual-absorption facilities.

TABLE 9. SULFUR DIOXIDE ABATEMENT COSTS FOR SULFURIC ACID PLANTS IN OHIO

State ID Number	(T) Capacity, tons/day[a]	Capital Cost, $	Operating and Maintenance Cost, $/year
Sulfur-Burning Plants		$C=51,404(T)^{0.60}$	$C=2,810(T)^{0.71}$
13-18-22-2594-P001	200	1,235,000	121,000
13-18-22-2594-P002	200	1,235,000	121,000
13-18-00-0151-P001	1000	3,243,000	379,000
14-31-35-0817-P001	600	2,387,000	264,000
16-77-04-0002-P003	180	1,159,000	112,000
Wet-Gas Plants		$C=97,283(T)^{0.61}$	$C=6,839(T)^{0.64}$
04-48-02-0014-P001	324	3,307,000	277,000
04-48-02-0014-P002	216	2,583,000[b]	213,000[b]

(a) Based on maximum SCC/hour

(b) This plant is already in compliance with EPA standards.

TABLE 10. ENERGY USED BY DUAL-ABSORPTION ABATEMENT OF SO_2 IN OHIO SULFURIC ACID PLANTS

ID Number	Capacity, tons/year[a]	Electricity		Fuel Oil	
		10^6 kwh/yr	10^9 Btu/yr[b]	10^6 gal/yr	10^9 Btu/yr[c]
Sulfur-Burning Plants		29.3 kwh/ton		2.97 gal/ton	
13-18-22-2594-P001	70,000	2.054	7.014	0.208	29.12
13-18-22-2594-P002	70,000	2.054	7.014	0.208	29.12
13-18-00-0151-P001	350,000	10.269	25.069	1.040	145.60
14-31-35-0817-P001	210,000	6.161	21.040	0.624	87.36
16-77-04-0002-P003	63,000	1.843	6.311	0.187	26.18
Wet-Gas Plants					
04-48-02-0014-P001	75,600	3.327	11.362	0.337	47.18
04-48-02-0014-P002[d]	113,400	4.991	17.044	0.506	70.84

(a) Based on operating 350 days per year

(b) Based on 3.415×10^3 Btu/kwh

(c) Based on 14.0×10^4 Btu/gal

(d) This plant is already in compliance with EPA standards.

Capital and operating costs for dual absorption were determined using the equations developed for existing wet-gas sulfuric acid plants. At a reported maximum rate of 8 tons sulfuric acid per hour, the daily capacity of the plant is 192 tons. Using appropriate constants A and B shown in the section on sulfuric acid, the following costs were obtained from the formula $C = AT^B$

Capital cost = $\$97,283\ (192)^{0.61} = \$2,404,000$

Operating and maintenance cost = $\$6,839\ (192)^{0.64} = \$198,000.$

Electricity consumption should be about 2.957×10^6 kwh/year (10.1×10^9 Btu/year) and fuel oil consumption about 300,000 gal/year (42×10^9 Btu/year).

Fuel Combustion Processes

Most of the "processes" in the Ohio EPA inventory emit sulfur from the combustion of sulfur containing fossil fuels. Thus, control of the emission of SO_2 from these sources is achieved by flue gas treatment or by low-sulfur fuel substitution, methodologies which are examined in a subsequent section of this report.

However, the problem in many of these type sources was that the fuel consumption was not directly displayed in the inventory as a specific SCC code, and may not have been included in the SCC process weight. Thus, a substantial effort was made to clarify the emission inventory for those inventories where it was possible. The process weight rates of the following industries were adjusted, where necessary, to reflect the input rate of process material and solid fuel (as opposed to the output process weight rate in the inventory).

Cement and Lime Kilns

Emissions of SO_2 in the cement industry arise from the combustion of coal in the kilns. Eighteen Emission Inventory Confirmation Reports for

sulfur dioxide emissions were examined for the cement industry. Fourteen of the sources were in compliance using the Process Weight Curve equation $E = 19.5 (\text{process weight})^{.6}$.*, while 4 exceeded the emission limitations. The uncontrolled emissions (calculated from the coal sulfur content) were assumed to be reduced by 75 percent if baghouse or scrubber were used to control particulate emissions, and by 50 percent if no controls or other control systems such as a electrostatic precipitator were used.** The SO_2 reduction is based on the knowledge that SO_2 reacts with the alkaline dust particles, and the reduction figures are from AP-42.

Emissions of SO_2 in the lime industry similarly arise from the combustion of coal in the kilns. Fourteen Emission Inventory Confirmation Reports for sulfur dioxide emissions were examined for the lime industry, and each source was in compliance using the Process Weight Curve equation $E = 19.5 (P)^{0.67}$. The uncontrolled emissions, which were calculated from the sulfur content of the coal, were assumed to be reduced 75 percent if a baghouse control system or wet scrubber control system were used to control emissions and to be reduced by 50 percent if no controls or other control systems were used, such as an electrostatic precipitator. The SO_2 reduction is based on the knowledge that SO_2 reacts with alkaline dust particles, and the reduction figures are from AP-42. Thus, the lime industry suffers no incremental cost from the proposed regulations.

Brick and Clay Industry

Eight Emission Inventory Confirmation Reports were examined for the brick industry. Emissions of SO_2 in the brick industry arise from the combustion of coal in the kilns. Five of the sources examined use coal with a sulfur content of 3.5 percent and are in violation of SO_2 emission limitation regulations using the Process Weight Curve. The remaining three sources meet the SO_2 emission limitation regulations. Two sources use natural gas in the kilns, while the other source uses a combination of natural gas and coal.

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* E = emissions lb/hr; P = process weight, lb/hr.

** The alkaline dust absorbs SO_2 even without particulate collection.

Eight Emission Inventory Confirmation Reports were examined for the Ceramic Clay manufacturing industry. Emissions of SO_2 in the ceramic clay industry arises from the combustion of fuel for drying. Since the above mentioned sources use natural gas for drying SO_2 emissions were considered to be insigificant. AP-42 indicates that SO_2 emissions arise from the sulfur content in the fuel.

Fiberglass Industry

Nine Emission Inventory Confirmation Reports were examined for the Fiberglass industry. The reports contained insufficient information to verify the SO_2 emissions from these sources.

Limestone/Gypsum/Refractory Industries

One Emission Inventory Confirmation Report for each of the above mentioned industries was examined. Each source was in compliance with SO_2 emission limitation using the Process Weight Curve equation.

Fossil Fuel Combustion for Steam Generation

The combustion of sulfur bearing fossil fuel for the generation of steam is the largest source of emissions in the state of Ohio. Battelle, as a part of its study, was directed to define a methodology for the analysis of costs, etc., for the control of SO_2 from non-utility steam boilers.

Two separate approaches were adopted. In the first approach, control would be achieved by the substitution of a lower sulfur fuel, incurring costs of mechanical modifications and incremental fuel costs. Battelle was directed to determine and provide the cost of required modifications: results of that analysis for non-utility boilers are presented herein.

In the second approach, control would be achieved by a flue gas desulfurization (FGD) unit. Battelle determined that, among the currently

availablce choices for FGD, only insignificant differences exist in costs. Thus, FGD is treated generically, with the FGD option specifying a dual-alkali system. Costs, etc. for this type of unit as a function of size are presented herein.

The disposal of sludge from FGD systems is identified as an area of separate study, as Ohio has introduced regulations restricting the placement of landfills. The wholesale application of FGD could present excessive demands on lime and landfills, and thus the FGD sludge disposal methodology presented herein specifically addresses these quantities.

Constraints and Costs in Changing from High-Sulfur to Low-Sulfur Fuels for Non-Utility Steam Generating Units

The purpose of this task was to examine and evaluate the constraints introduced in the operation of non-utility commercial and industrial steam generating units in Ohio, when changing from high-sulfur fuels, including the estimation of costs of capital equipment and the operating and maintenance costs involved in making fuel changes to effect compliance with environmental air quality regulations.

It must be pointed out that there is difficulty in anticipating the effect of changes in coal properties when changing coals in existing equipment for one of the several modes of firing. Coals vary widely in their chemical and physical characteristics. Thus, in the prime interest of using coals of lower sulfur content, other characteristics of the coals can differ in degree which often may affect their performance in a given type of equipment. For example, were a low-sulfur eastern coal to be substituted for a high-sulfur Ohio coal presently in use with a traveling grate stoker, operating difficulties would likely be encountered because of the strongly caking characteristics of these coals. In a short-term consideration of the stated objectives, therefore, it is not possible to cover specifics but only generalizations.

For this analysis it was assumed that only eastern low-sulfur coals were to be given consideration. Wholesale-dealer distribution setups for

the marketing of low-sulfur western coals to supply numerous small non-utility installations are not available in Ohio, and are not likely to be available in the near future.

General Capacity Ranges of the Several Stoker Modes of Firing Boilers

Table 11 lists capacity ranges of non-utility boilers in terms of Btu per hour heat input and approximate rates of steam generation. These equivalent ranges assume that a rate of heat input of 1.0×10^6 Btu per hour is equivalent to raising approximately 700 lb of steam per hour at a boiler efficiency of 75 percent. Size ranges from 1a through 3 represent the general range of "commercial" boilers. The range from sizes 4 through 8 represent "industrial" steam-rising generators. A few pulverized-coal-fired industrial boilers are in the range from, say, 100,000 lb steam per hour[13] to the top of class 8, but most pulverized-coal-fired utility boilers operate at higher steam outputs. Most stoker-fired boilers have a capacity of considerably less than 400,000 lb steam per hour, which can be considered the upper limit of this class of firing, except for spreader stoker installations.

Underfeed stokers are of two main types -- single retort, for the commercial and small industrial stoker-fired installations having capacities of up to about 20,000 lb steam per hour, and multiple retort systems which have been applied to boilers raising up to about 400,000 lb steam per hour Multiple retort stokers now are not widely used[14].

The traveling grate stoker has had wide application in the burning of a wide variety of solid fuels. As shown in Table 11, the nominal capacity range for these stokers is approximately in the range of 10,000 to 100,000 lb of steam per hour, although installations of higher capacity are in use.

The vibrating grate stoker utilizes the crossfeed principle of burning, as does the traveling grate stoker. Instead of a traveling grate, the stoker is arranged to impart rectilinear motion of short stroke from front to back, with coal fed from a hopper at the front and ash discharged

TABLE 11. GENERAL CAPACITY RANGES OF STOKER- AND PULVERIZED-COAL FIRED COMMERCIAL AND INDUSTRIAL STEAM GENERATING UNITS(a)

Size No.	Range of Heat Input Btu/hr x 10^6	Range of lb Steam/hr(b)	Stoker Fired, Approximate Capacity Range					
			Underfeed		Traveling Grate	Vibrating Grate	Spreader	Pulverizer
			Single Retort	Multiple Retort				
1a	0.5 - 1.4	350 - 980						
1b	1.5 - 2.4	1,050 - 1,680						
2	2.5 - 5.4	1,750 - 3,780	(c)					
3	5.5 - 10.4	3,850 - 7,280						
4	10.5 - 20.4	7,350 - 14,280						
5	20.5 - 50.4	14,350 - 35,280						
6	50.5 - 100.4	35,350 - 70,280	(d)					
7	100.5 - 200.4	70,350 - 140,280		(e)				
8	200.5 - 500.4	140,350 - 350,280						Most are larger-in the utility range

(a) Pulverized coal is used only for large industrial sizes.

(b) Assume: 1 x 10^6 Btu/hr 700 lb steam/hr (assumed boiler efficiency about 75 percent)

(c) Nominal commercial installation range

(d) Nominal industrial installation range

(e) Utility range, pulverized coal and cyclone installations

Source: References 10, 11, 12

at the rear. The high end of the capacity range can be about 50 percent higher than the usual traveling grate system, or up to around 150,000 lbs of steam per hour.

The main difference between a spreader stoker and a traveling grate stoker is that the spreader stoker employs a combination of the combustion of coal particles in suspension and a thin, fast burning full bed, whereas the traveling grate uses the principle of mass burning on the moving grate. Accordingly, the spreader stoker is more sensitive to fluctuations in load demands. The nominal capacity range of vibrating stoker installations is 30,000 to 150,000 lbs of steam per hour.

Although there are a few pulverized-coal fired installations in Ohio in what might be termed the industrial capacity range, they are believed to be rare. The usual application of pulverized-coal firing is for the large electric utility units, employing firing rates of at least several times that of the upper range of the industrial No. 8 size listed in Table 11.

Coal Characteristics in Relation to Use in Stoker Firing of Non-Utility Boilers

It is not the total sulfur content per se that affects the selection of coals for non-utility stoker-fired commercial and industrial steam generating units. Other coal characteristics are important in the selection process in effecting a change from a high to a low-sulfur coal, such as its caking and ash fusion properties, ignitability characteristics, and size range.

Table 12 summarizes some generalized constraints involving coal characteristics that are involved in changing from high sulfur to low sulfur eastern bituminous coals for commercial and industrial boilers. The constraints are indicated according to the several types of stokers prominently associated with the steaming capacities of interest.

TABLE 12. SOME GENERALIZED CONSTRAINTS INVOLVING COAL CHARACTERISTICS IN CHANGING FROM HIGH SULFUR TO LOWER SULFUR EASTERN BITUMINOUS COALS FOR COMMERCIAL AND INDUSTRIAL BOILERS

Method of Firing	Volatile Matter	Ash Softening Temperature	Swelling Index	Heating Value(e)	Grindability	Change in Particulate Emissions
Underfeed	-	-	(c)	-	-	(g)(h)
Traveling Grate	-	-	(d)	-	-	(g)(h)
Spreader	(a)	-	-	-	-	(g)(h)
Vibrating Grate	-	-	-	-	-	(g)(h)
Pulverized Coal	-	(b)	-	-	(f)	(g)(h)

(a) With spreader stokers, coals with the higher volatile matter contents (above anthracite) work better because of better ignition of particles in suspension.

(b) For dry-bottom pulverized coal units the ash fusion properties of the coal, within limits, are not a constraint. For slag-top and cyclone systems, coals with high ash-softening temperatures cannot ordinarily be used.

(c) Coals with high swelling indexes may be a constraint through formation of coke trees under low loads.

(d) Since there is little fuel-bed agitation, coals with high free-swelling indexes can result in caking and incomplete combustion by the time the dump end of the grate is reached.

(e) No constraint as long as only Eastern bituminous coals are involved in the change. If changes to the lower rank western subbituminous coals were involved, some derating of the boiler would probably be indicated.

(f) A significant increase in the grindability index of the low-sulfur coal may require additional pulverizer capacity.

(g) No significant change assuming about the same ash content with same mechanical collectors.

(h) Low-sulfur coal use may dictate enlarged electrostatic precipitator.

Single Retort Underfeed Stokers. The single retort underfeed stoker is able to burn a wide range of coals, and in most instances a change from a high-sulfur to a low-sulfur coal can be accomplished successfully. Coke tree formation with a very strongly caking coal combined with low ash-softening temperatures can at low loads lead to irregular fuel beds and clinkering. Coal sizing is of importance, with limitations usually placed on the amount of slack sizes of coal.

Multiple Retort Underfeed Stokers. Criteria for the use of coal in multiple retort stokers follows generally those for single retort stokers. Again, limitations are placed on the slack sizes and on low ash-softening temperatures, and the fed coal should be evenly distributed according to size across the feed hopper of the stoker.

Traveling Grate Stokers. Traveling grate stokers are widely used for steam generation in boiler sizes up to about 100,000 lb steam per hour. They are adaptable to a wide range of coals and waste fuels with the exception of strongly caking coals. Anthracite, relatively free-burning bituminous coals, and low rank coals are the preferred fuels. Combustion Engineering[14] notes that some bituminous coals of the more strongly caking type can be burned if the coal is of optimum size, has been allowed to weather, and is tempered to a total moisture content of about 15 percent. Generally, however, the strongly caking bituminous coals are to be avoided for use by traveling grate stokers. Coal sizing is essential.

Spreader Stokers. Spreader stokers are capable of burning a wide range of coals and some waste fuels. Because of the important ignitability of the small and finely sized particles that are burned in suspension above the grate, the anthracitic coals of low volatile-matter content are to be avoided.

Vibrating Grate Stokers. This type of stoker was first developed in Europe to burn the low-rank lignitic brown coals. During the past twenty years, this stoker has been used successfully to burn a wide variety of American coals, both free burning and strongly caking. It is not known whether stokers of this type are operating in Ohio.

Pulverized Coal Units. Although most commonly applied to boilers of electric utilities, pulverized coal burning has also been applied to steam generators of the larger industrial installations. In general, the minimum-sized application for pulverized coal units is about 100,000 lb steam per hour. Almost all types and ranks of coal can be burned in pulverized form, the chief constraint residing in the properties of their contained ash, as broadly evidenced by the ash-softening temperature. Coals with ash-softening temperatures above about 2500 F are not to be used in slag-top units nor in cyclone fired units since their operation is conditioned on the presence of slag formation. The lower range of low ash-softening temperature may not be desirable for dry bottom boilers, when certain relationships between constituents of the ash are unfavorable[15].

Summary

With exceptions of certain coal characteristics noted in the foregoing with respect to the common types of stokers as employed by non-utility commercial and industrial steam generators, the switching of coals from a high sulfur content to a low sulfur content, in itself and without consideration of specific situations, should not result in increased expenditures relating to capital equipment and operation and maintenance charges. This assumed previous compliance with particulate emissions. If this were not true, capital expenditures would be required to satisfy particulate regulations anyway, without regard to the objective of lowering sulfur oxide emissions.

The foregoing statement is a generalization, based on a cursory, short term examination. Only by proceeding on the basis of specifics (stoker, present fuel type, present degree of compliance with particulate and SO_x regulations, etc.) could costs of additional (if any) capital equipment and operating and maintenance charges in fuel switching be estimated.

Costs for Switching from Coal Fired to Oil Fired Operation of Non-Utility Steam Generating Units

Although this task was also to be examined, it was found that data relating to capital charges, and to operating and maintenance costs of changing from coal to oil fuel for non-utility steam generating units were not readily available. Accordingly, it was not possible to determine even generalized capital, operating and maintenance costs for the several classifications of steam generators. However, the primary cost is that of the incremental cost of fuel, which is considered in the costing algorithms.

FGD Costs for Non-Utility Boilers

In order to meet the new proposed Ohio SO_2 emission regulations non-utility boilers burning moderate to high-sulfur coal or residual fuel oil will, in many counties, have to implement some type of SO_2 control strategy. One option is to add a flue gas desulfurization (FGD) system. Currently the leading FGD systems are lime, limestone, and double-alkali scrubbing, with the double alkali process representing the most developed process for non-utility boilers. Comparison of the capital costs for the three systems on small (125 MWe) utility boilers shows that the costs for the leading systems are very similar. Compared to the double-alkali process costs of the lime scrubbing system are approximately 3 to 4 percent higher, and the limestone process, 9 percent higher. Operating costs for the three processes all fall within the same estimated range[16]. The variation in costs between the different processes are therefore within a $\pm$ 20 percent range and thus all FGD costs can be approximated by any one of the FGD systems. Therefore, the double alkali process, because of its high degree of development and the

availability of relatively accurate cost data for nonutility boiler applications, will be the basis for all FGD calculations. Cost, energy utilization, and sludge production estimates will be based on the experience of the GM double-alkali process at the Parma, Ohio plant[17], and internally available information[18].

Capital Costs

The capital amortization contribution to the GM system's operating cost is reported as $4.55/ton coal burned. For 55,000 ton per year (TPY) of coal burned, this is equivalent to approximately $3.5 million in mid-1974 costs. This figure was adjusted to January 1, 1975 cost by use of an escalation factor obtained from the ratio of Chemical Engineering Plant cost index $\left(\frac{177.8 - \text{December, } 1974}{164.7 - \text{June, } 1974}\right) = 1.08$[4], which increased estimated capital cost as of January, 1975 to $3.78 million. The capital costs, since sludge disposal is off-site, are not significantly affected by the coal's sulfur content. The cost for double-alkali FGD based on 80 percent SO_2 removal can be expressed as a function of this cost, plant capacity in TPY of coal burned, and an exponential scaling factor.

The G-M plant at Parma consists of 2 - 150 MM Btu boilers and 2 - 90 MM Btu boilers. The Ohio confirmation inventory sheets indicate 8736 hrs/yr operation (~100 percent, probably somewhat on the high side). On the basis of an internal BCL report on this plant[3], the load factor for this plant is only 40 percent. This is consistent with the reported 55,000 tons/year coal usage. Also, excess air averages approximately 100 percent for the four boilers, so that flue gas volume is about 148,000 cfm. Thus, it appears that the FGD plant capacity is scaled to maximum flue gas volume and would handle the flue gas from a plant burning considerably more coal per year, with a higher load factor and/or a lower percent excess air. It is assumed that the excess air is reasonably typical of industrial coal-fired boilers now in service in Ohio (although new boilers would be expected to be capable of operation at much lower excess air percentages, no more than, say, 20 percent). Thus, no provisions for excess air variations are included in the cost methodology.

However, load factor is a more definable parameter, for which estimates can be computed from the available inventory data; and this factor is incorporated into the methodology.

It should be noted that the 4-boiler GM plant (480 MM Btu/hr capacity) is among the largest non-utility boiler plants in the state; most FGD plants will be smaller than this one.

There are no accurate data available on scaling factors for double-alkali processes for non-utility boilers. There are, however, data for utility boiler FGD systems. Because scaling factors should be very similar for utility and non-utility cases, the exponential scaling factor of 0.83 obtained from comparing estimated costs of a 750 and 125 MWe utility units will be employed for these calculations. The cost equations are noted below:

$$\text{Capital Costs, \$} = \$415{,}000\ [\text{Coal Consumption, Maximum Tons/Hr}]^{0.83}$$

$$= \$940\ \left[\frac{(\text{Coal, TPY})}{(\text{Load Factor})}\right]^{0.83}$$

Alternatively, for a given flue gas flow, the FCD could be expressed as:

$$= (3.78 \times 10^{6}) \left[\left(\frac{\text{Flue Gas, ACFM}}{148{,}000}\right)\right]^{0.83}$$

$$= \$193.30\ [(\text{Flue gas, ACFM})]^{0.83}.$$

Capital costs estimated by the above algorithms would be expected to be applicable to plants burning up to 100,000 tons of coal per year, and to below the size where FGD is truly an economically feasible option, and are thus valid over the practical range over which FGD might be applied.

Capital costs for FGD systems for oil-fired boilers are calculated in a similar fashion. However, it should be noted that oil-fired boilers tend to be operated with lower percentages of excess air than do coal boilers, so that an oil-fired boiler plant producing 148,000 ACFM of flue gas will be significantly larger than the GM plant used for the cost basis, possible as much as 50 percent if excess air is no more than about 20-25 percent.

At 20 percent excess air, the 148,000 cfm FGD capacity of the GM plant would service a boiler plant (operating at the GM 40 percent load factor) burning approximately 15,000 M gal of residual fuel oil/year. In Btu input, this is a little greater than 150 percent of the GM plant size.

The cost algorithm, on a flue gas basis, would be the same as that for coal-fired boilers. On a fuel input basis, and the assumptions noted above, it would be

$$\text{Capital Cost, \$} = (3.78 \times 10^6) \left[\frac{\text{M gal Resid/yr}}{15{,}000}\right]^{0.83}$$

$$= \$604 \left[\frac{\text{M gal Resid/yr}}{\text{Load Factor}}\right]^{0.83}$$

Another factor in the estimation of FGD system capital costs is the degree of required retrofit. The basis for the cost algorithms generated are based on a moderate retrofit case. Costs for a new facility, not requiring retrofit, would likely be less. However, no data are available to accurately assess these differences. Assuming sufficient space is available, the cost for a new facility is assumed, for the purposes of these cost estimates, to be approximately equal to the moderate retrofit case represented by the presented equations.

In some cases, the required SO_2 removal necessary to meet the emission levels for a particular situation will be significantly less than the 80 percent removal possible with the double-alkali wet-scrubbing process. In these cases the advantage of flue gas by-pass, wherein a fraction of the gas stream is treated by FGD and the remainder by-passed to the stack, will be explored. By-pass will be discussed in another section.

Operating and Maintenance Costs*

The reported operating and maintenance (O&M) costs were adjusted to approximate January 1, 1975 costs, using the chemical engineering scale (4). Since individual O&M cost components vary differently with capacity, it was necessary to scale each component separately to determine a reasonable overall O&M cost scaling factor. The O&M costs consist of the following 5 cost components: chemicals, utilities, labor, maintenance, and miscellaneous costs. The adjusted estimated cost is $432,300/year for 55,000 TPY of 2.5 percent sulfur coal burned. From each component's scaling factor an estimate was made for a facility of twice the GM plant's capacity. This calculation is summarized below:

* The cost of disposal was backed out of these costs and added back in with a uniform waste disposal costing methodology described later.

Chemicals	$(\$114,950/yr)(2)^{1.0}$	= $229,900/yr
Utilities	$(\$137,500/yr)(2)^{1.0}$	= $275,000/yr
Labor	$(\$128,700/yr)(2)^{0.61}$	= $196,430/yr
Maintenance	$(\$ 47,850/yr)(2)^{0.61}$	= $ 73,030/yr
Miscellaneous	$(\$ 3,300/yr)(2)^{1.0}$	= $ 6,600/yr.

From the original costs and the estimate of O&M cost for a double capacity facility, an average overall exponential scaling factor of 0.853 was determined. The chemical cost component of the O&M costs is a function of the percent sulfur in the coal. This relationship is assumed linear, i.e., a doubling of sulfur content of coal doubles the chemical costs. The O&M cost for 2.5% sulfur coal at the Parma GM plant was estimated at $432,300/year. For a 5 percent sulfur coal, this cost would rise to $547,250/year. The coal sulfur content can be factored into the O&M cost as follows:

$$\left(\frac{\text{O\&M cost @ 5\% sulfur}}{\text{O\&M cost @ 2.5\% sulfur}} = \frac{\$547,250/yr}{\$432,300/yr}\right) = \left(\frac{5\% \text{ sulfur}}{2.5\% \text{ sulfur}}\right)^{Y}$$

where the exponential scaling factor, Y, equals 0.34. The influence of capacity and coal sulfur content can be factored into an O&M cost algorithm as follows:

$$\text{O\&M Cost, \$/yr} = (\$432,300)\left[\left(\frac{\text{Coal consumption, TPY}}{55,000 \text{ TPY}}\right)^{0.83}\left(\frac{\% S}{2.5}\right)^{0.34}\right]$$

which can be simplified to

$$\text{O\&M Costs}\left(\frac{\$}{Yr}\right) = (\$28.64)\ [(\text{Coal consumption})^{0.853}(\% S)^{0.34}]$$

Like the capital costs, the O&M costs calculated by this equation should be reasonably accurate for FGD units for all non-utility coal-fired boiler plants in the size range where FGD is an economically feasible option.

O&M costs for FGD systems for oil-fired boiler plants are calculated similarly. Since the basis for cost estimation is a coal-fired boiler plant, the coal percent-sulfur content must be converted to an equivalent residual fuel oil sulfur content. For 2.5 percent sulfur coal, the equivalent residual fuel oil sulfur content is 3.8 percent (based on 12,500 Btu/lb coal, 150,000 Btu/gal residual fuel oil, and a density of 7.88 lb residual fuel oil/gal.).

The O&M cost equations for an oil-fired boiler plant FGD system, on a flue gas basis can be derived from the GM plant data as follows:

$$\text{O\&M Costs, \$/yr} = \$432{,}000 \left[\left(\frac{\text{Flue gas, ACFM}}{148{,}000}\right)^{0.83} \left(\frac{\%\ S}{3.8}\right)^{0.34}\right]$$

$$= \$10.68\ [(\text{Flue gas, ACFM})^{0.853} (\%\ S)^{0.34}]$$

O&M costs can also be expressed on a fuel input basis, using the assumptions described above for oil-fired boilers:

$$\text{O\&M Costs, \$/yr} = (\$432{,}000) \left[\left(\frac{\text{M gal Resid/yr}}{15{,}000}\right)^{0.853} \left(\frac{\%\ S}{3.8}\right)^{0.34}\right]$$

$$= \$75.19\ [(\text{M gal Resid/yr})^{0.853}\ (\%\ S)^{0.34}]$$

The cost algorithms presented are based on data from a retrofitted FGD system. The O&M costs should not, however, be significantly affected by whether the facility is new or required retrofitting.

Flue Gas By-Pass Option

For plants or individual boilers which have a required SO_2 removal requirement (N) below 80 percent, the flue gas by-pass option is employed. To offset the additional costs, added complexity, etc., of the by-pass option, only boilers capable of meeting their county's emission regulation while by-passing a minimum of 25 percent will be considered, i.e., in terms of required SO_2 removal, the by-pass option will be considered for plants with N of 60 percent or less. Under the by-pass system the effective quantity of coal treated by FGD for cost purposes will be a fraction, Z, of the total quantity of coal burned. Based on the assumption that the double alkali process removes 80 percent of the inlet SO_2, the fraction of coal requiring treatment can be represented as follows:

$$Z = N/0.8.$$

If the by-pass option is employed, both the FGD system capital and operating costs will be reduced because of the smaller sized unit required and the elimination of direct reheat requirements. Based on the savings possible by elimination of the steam reheat unit, the by-pass FGD capital costs can be represented as 95.3 percent of the original capital costs[1] or as follows:

$$\text{Capital Costs, \$} = (\$395{,}800)\ [(\text{Maximum Coal Usage, Tons/hr})(Z)]^{0.83}$$

For a residual fuel oil FGD system the corresponding equation would be:

$$(\$604)\ \left[\frac{(Z)(\text{M Gal Resid/yr})}{\text{Load factor}}\right]^{0.83}$$

The O&M costs algorithm for coal-fired boiler plants is modified as follows:

$$= (\$26.78)\ [(Z \times \text{Coal usage, TPY})^{0.853}\ (\%\ S)^{0.34}]$$

and for oil-fired boiler plants as follows:

$$(\$10{,}00)\ [(Z \times \text{Flue Gas Volume, ACFM})^{0.853}\ (\%\ S)^{0.34}]$$

Energy Usage

Energy will be expended in the FGD process in two forms. First, electricity for fans, pumps, thickeners, vacuum filters, etc., will be required. Second, low-pressure steam will be required for stack gas reheat. Of source, if the flue gas by-pass option is employed, the steam requirement for reheat will be eliminated, and the electricity consumption will be decreased by the by-pass fraction.

The energy requirements can be quantified in terms of the actual physical units from the Parma GM plant as follows:

Electricity	88 kwh/ton coal burned or 300,344 Btu/ton coal burned
Steam	600 lb steam/ton coal burned or 554,400 Btu/ton coal burned.

For residual fuel oil, the electricity and steam consumption rates can also be calculated. However, because of the significantly smaller quantity of excess air employed with fuel oil combustion, (10-25 percent excess air for fuel oil combustion vs. 100 percent excess air for the coal-fired Parma GM plant) the quantity of flue gas treated is significantly lower. Consequently, the electricity and steam requirement per unit of fuel or Btu input is much lower than coal. An appropriate algorithm including a flue gas flow rate factor is noted below:

Electricity 4.74×10^6 kwh/yr $\left(\frac{\text{Flue gas, ACFM}}{148,000}\right)$ or

1.6519×10^{10} Btu/yr $\left(\frac{\text{Flue gas, ACFM}}{148,000}\right)$

Steam 3.3×10^7 lb steam/yr $\left(\frac{\text{Flue gas, ACFM}}{148,000}\right)$ or

$3,0492 \times 10^{10}$ Btu/yr $\left(\frac{\text{Flue gas, ACFM}}{148,000}\right)$

One drawback of these equations are that they are based on the operating schedule of the Parma plant. If a non-utility boiler is employed for a smaller fraction of the year (e.g., for space heating), the methodology for O&M costs for fuel oil combustion will over-predict actual O&M costs. However, the ratio of quantities of bituminous coal burned in Ohio to fuel oil combustion is approximately 5 (on a Btu basis), and thus the potential error as noted is expected to be insignificant.

Sludge Production

A number of assumptions were required to calculate the quantity of sludge produced by FGD systems on non-utility boilers, as follows:

(1) Stoichiometry = 1.5 (50% excess lime)

(2) Solids in the filter cake = 50 percent

(3) SO_2 removal efficiency = 80 percent

(4) Sulfur content of the fuel = variable

(5) The relationship between fuel sulfur content and sludge generation rate is assumed linear

(6) The sludge generation rate is independent of fuel burning capacity.

From the Parma GM plant data the sludge production is reported as 400 lb/ton coal burned (at 65 percent solids). This is equivalent to 520 lb/ton at 50 percent solids. This data can be arranged in sludge generation algorithms as follows:

$$\text{Sludge, lbs} = (520)\left(\frac{\%\ S}{2.5}\right)^{(Z)}\ (\text{Coal Usage, TPY})$$

$$= 208\ (\%\ S)(Z)(\text{Coal Usage, TPY})$$

where Z is the fraction of coal burned treated by the FGD system.

The analogous algorithm for fuel-oil fired boiler plants is calculated similarly. The comparable percent sulfur is 3.8 percent, and 167 gal. of residual fuel oil is equivalent in heat input to 1 ton of coal.

$$\text{Sludge, lbs} = 520\left(\frac{\%\ S}{3.8}\right)(Z)\ (167)\ (\text{M Gal. Resid/yr})$$

$$= 819\ (\%\ S)(Z)(\text{M Gal. Resid/yr})$$

Also, for comparative purposes, it should be noted that the sludge production rate for limestone FGD scrubbing is 17 percent greater, and lime scrubbing 10 percent greater, than with the double alkali FGD process.

Life of Capital

Because of the high corrosive/erosive nature of most FGD systems, it is difficult to accurately estimate the service life of the wet scrubbing facility. In addition, because no double alkali plants have been in existence for any extended period of time, no historical data are available. However, from an assessment of service lives of similar equipment in similar high corrosive/erosive environments, an estimate of approximately 15 years is reasonable.

FGD Sludge Disposal Costs

The utilization of a flue gas desulfurization unit will result in the generation of volumes of FGD sludge. The sludge is a calcium sulfite/sulfate/carbonate sludge containing approximately 50 percent solids. The users of FGD systems will have to incur the costs necessary to dispose of the sludge.

The physical and chemical properties of flue gas desulfurization wastes exhibit wide variations because many factors influence the character of the sludge, such as:

- Sulfur and ash characteristics of the fuel
- Boiler operation (gaseous flow rate and load factor)
- Lime and/or limestone characteristics
- Scrubber operation (separate/combined particulate control and recycle operations)
- Sludge treatment and conditioning.

The nature of the sludge limits sludge treatment, handling, and/or disposition options. The final nature of the disposal sludge is also a significant factor in regard to potential environmental impacts.

Two broad sludge disposition approaches are adopted by industries--the throwaway methods and utilization processes. Ponding and landfilling (retention impoundments) currently provide the major throwaway mechanisms for disposal. Clarified liquors are often discharged to surface waters. For the case of "closed loop" operation, this discharge (blowdown) is greatly reduced in volume. The sludge could provide varying degrees of surface and groundwater pollution depending predominantly upon chemical composition, solubilities of the sludge components, and the location, design, and operation of the disposal site. Some of the sludge wastes are very resistant to dewatering and can reslurry in retention impoundments and are highly prone to transport by erosion. Seepage of leachants from the impoundment to both consolidated and alluvial aquifers can cause down-gradient deterioration of water resources.

The problems of utilization processes are great. There are limited utilization options or recycle options which are cheap enough for the tremendous amounts of calcium sludges produced annually. The few proven utilization processes like mineral aggregate and paving subbase have so far involved only a small fraction of the annual tonnage of calcium sludges. Thus for the purposes herein only disposition by a "throwaway method" has been considered.

The production of flue gas desulfurization sludges generated during the SO scrubbing of coal burning systems is dominately dependent on (1) the amount of coal burned, (2) the sulfur content of the coal, (3) the characteristics of the scrubbing agents, and (4) the design SO_2 removal efficiency. The disposition weight and particularly the volume of the sludge will also depend on the operation ratio of sulfite to sulfate. The ash content reading and removal by the SO_2 scrubber also effects the sludge production rate. Actual operation sludge production rate can vary by as much as 20 percent from the mean generation estimate (also assuming 50 percent water by weight).

The estimated density of the FGD sludge, which is strongly influenced by the sulfite/sulfate ratio, may range from less than 65 to slightly more than 115 pounds per cubic foot. A substantial expenditure of dewatering energy (and therefore dollars) would be necessary to reach the higher value (~maximum bulk density) which would be more than 75 percent solids. Operational experience indicates that the solids fraction of FGD sludges for disposition can range from 35 to 65 percent[20]. For the purposes here FGD sludges for disposition were assumed to be at about 50 percent solids with a density of 89.1 pounds/ft^3.

In determining FGD hauling costs a double case estimation procedure and two scales of operation were assumed. To reflect costs of hauling relatively smaller waste volumes (<50 tons/day @ 50% solids : 5 day week), costs reported for municipal sewage sludge hauling were temporally (January, 1975 dollars, CE Cost Index) and spatially (FGD sludge density @ 50% solids ~90 pounds/ft^3) adjusted. For larger waste volumes in-State contract waste haulers were contacted by phone in order to estimate hauling rates[22]. The cost estimates for these cases assuming a ten mile haul (5 days/week) are summarized below, which includes both labor and mechanical equipment depreciation.

Case I	Case II
Short haul and/or low volumes	Long haul and/or high volumes
40 tons/day	400 tons/day
$0.24/ton-mile	$0.10/ton-mile
$192/day	$800/day
$4.80/ton	$2.00/ton

With both cases considered, hauling costs can be estimated as $/Day = 15.52 (tons sludge/day)$^{0.658}$. It should be noted that these estimates are means of 10 values for Case I (ranging from $0.05-0.49/ton-mile) and 5 values for Case II (ranging from $0.065-0.14/ton-mile), i.e. there is a substantial range of costs.

Estimation of land disposal costs was based on sanitary landfill cost estimates.[23,24] The Chemical Engineering plant cost index was used to develop January, 1975 cost estimates. FGD sludge density of ~90 pounds/ft^3 (@ 50% solids) was also assumed. Both relatively low and high expected disposal volumes (<100 tons/day[24] and ~1000 tons/day[25], respectively) and associated costs were considered. With the ten disposal volumes considered (ranging from 15 tons/day - 1600 tons/day) the disposal costs can be estimated as $/Day = 24.75 (tons sludge/day)$^{0.606}$.

It should be noted that the price of the land is assumed to be included in these costs. FGD sludge disposition problems/regulations were assumed to be comparable with those of present landfull practices.

In estimating FGD sludge disposal fuel requirements both hauling and disposal needs were considered. Hauling requirements were based on a maximum truck capacity of 20 cu yd (payload ~24 tons), an average diesel fuel consumption of 3.5 miles per gallon and haul distance of 10 miles. Based on two tractor-bulldozers (23,500 and 50,000 pounds), diesel fuel usage at the disposal site was estimated at 0.5 gallons per ton of sludge placed. In total then, diesel fuel requirements for FGD sludge disposition can be estimated by gallons/time = 0.738 (Tons sludge/Time).

Considering FGD sludge at 50 percent solids to have a density of 89.1 pounds/ft^3 the disposal volume can be estimated as: Volume/Time = 5.15×10^{-4} (Tons of sludge/Time). Assuming an average disposal depth of 20 feet (probably a high estimate) required disposal acreage/time = 2.575×10^{-5} (Tons sludge/Time).

In summary, the methodology for FGD sludge disposal costs entails the following 4 equations:

1) Hauling cost, \$/day = \$15.52 (TPD sludge)$^{0.658}$
2) Disposal cost, \$/day = \$24.75 (TPD sludge)$^{0.606}$ (including cost of land)
3) Energy, Btu x 10^6/yr = 0.103 (Tons/yr sludge)
4) Area, acres/yr = 2.75×10^{-5} (Tons/yr sludge) (@ 20 feet deep).

These costs were provided to EPA for use in calculating total FGD costs.

GROWTH ESTIMATES

The growth rates used in this project represent the latest estimates developed by the Region V U.S. EPA staff. In the Technical Support Document[1] tables were presented listing growth rates for four different 2-digit SIC codes in each of Ohio's 30 urban counties. Industries represented by these four SIC codes -- 28 (chemicals and allied industries), 29 (petroleum refining and related industries), 32 (stone, clay, glass and concrete producing), and 33 (primary metals) are responsible for a large part of the SO_2 emissions produced by industrial processes. Census data, when available, were the basis for the county by county projections. In some counties the data were not available; for example, disclosure of census material is restricted when an industry is the only one of its type in a county.

Subsequent to the issuance of the Technical Support Document, EPA has revised a few of the growth factors for the four two-digit SIC industries and compiled some additional factors for other industries which are not major SO_2 producers. They have also assembled a county-by-county listing of projected population growth percentages for use in estimating future industrial growth in non-urban counties. County population projections may also be applied to the urban county industries for which no growth estimates by SIC code are available. For this task Battelle has rounded off all growth estimates to the nearest percent. While some estimates were specifically calculated as zero, others which are less than $\pm$ 0.5 percent have been rounded off to zero and labeled as non-significant.

Essentially, all growth projections were obtained from the Region V staff although some discussion was also conducted with staff members of Ohio's Department of Economic and Community Development and with Battelle-Columbus' staff members who have previously been engaged in preparing projections for Ohio.

Only limited data were available to EPA for projecting the growth of those industries falling under SIC Code 29, petroleum refining and related industries. Growth factors of 6 percent in Lucas County and one percent in Hamilton County were used, while petroleum refining and related industries in the remaining counties were predicted to grow at the expected state average for this industry 2.4 percent (rounded off to 2 percent). Table 13 gives estimated growth rates in percent for each Ohio county and by SIC Code.

Only two or three Ohio process industries are affected by the SO_2 limits in the current set of Federal New Source Performance Standards. Ohio has no additional requirements limiting emissions from new sources. For those sources specifically covered by both the New Source Performance Standards and the proposed Ohio SO_2 regulations, the New Source Performance Standards are more strict. Table 14 gives New Source Performance Standards applicable to Ohio industrial processes which emit SO_2. Industries which are regulated by NSPS are represented in the assembled data tape with no growth to cancel economic effects attributable to NSPS.

TABLE 13. OHIO GROWTH FACTORS BY COUNTY AND SIC

	Growth Rates in Percent				
County/SIC Codes	28	29	32	33	All Others Not Listed
Adams		2			4
Allen		2			-1
Ashland		2			1
Ashtabula (U)	10	2	0	0	0
Athens		2			-1
Auglaize		2			1
Belmont (U)		2	2		0
Brown		2			2
Butler	0	2	0	0	2
Carroll		2			3
Champaign		2			1
Clark		2	0	0	0
Clermont		2			2
Clinton		2			1
Columbiana (U)		2	1		1
Coshocton		2			1
Crawford		2			0
Cuyahoga (U)	6	2	3	1	-2
Darke		2			2
Defiance		2			0
Delaware		2			4
Erie		2			1
Fairfield		2			3
Fayette		2			1
Franklin (U)	8	2	6	0	1
Fulton		2			2
Gallia		2			2
Geauga (U)		2			1
Greene		2	0	0	0
Guernsey		2			1
Hamilton (U)	3	1	0.0	0	-1
Hancock		2			1
Hardin		2			1
Harrison		2			1
Henry		2			.
Highland		2			1
Hocking		2			1
Holmes		2			2
Huron		2			1

TABLE 13. (Continued)

County/SIC Codes	Growth Rates in Percent				
	28	29	32	33	All Others Not Listed
Jackson		2			1
Jefferson (U)		2	-1	4	0
Knox		2			1
Lake (U)	0	2	4	0	1
Lawrence		2	0		2
Licking		2			1
Logan		2			1
Lorain (U)	0	2	0	0	1
Lucas (U)	9	6	0	0	0
Madison		2			2
Mahoning (U)		2	3	1	-1
Marion		2			1
Medina		2	0	0	3
Meigs		2			2
Mercer		2			1
Miami		2			1
Monroe		2			0
Montgomery (U)	6	2	0	3	-1
Morgan		2			2
Morrow		2			2
Muskingum (U)		2	0		1
Noble		2			1
Ottawa		2			1
Paulding		2			1
Perry		2			2
Pickaway		2			2
Pike		2			2
Portage		2	0	0	1
Preble		2			1
Putnam		2			1
Richland		2	0	0	0
Ross		2			0
Sandusky		2			1
Scioto		2	0	0	1
Seneca		2			0
Shelby		2			1
Stark (U)	0	2	1	2	1
Summit (U)	0	2	2	0	-1

TABLE 13. (Continued)

County/SIC Codes	Growth Rates in Percent 28	29	32	33	All Others Not Listed
Trumbull(U)		2	3	1	1
Tuscarawas		2			1
Union		2			2
Van Wert		2			0
Vinton		2			3
Warren		2			0
Washington(U)	12	2	0		1
Wayne		2			1
Williams		2			1
Wood		2	0		3
Wyandot		2			1

Code

0 = No significant growth, i.e. < 0.5 percent
0.0 = Zero growth
Blank = No data given by EPA
(U) = Urban county

TABLE 14. NEW SOURCE PERFORMANCE STANDARDS (NSPS) APPLICABLE TO OHIO INDUSTRIAL PROCESSES WHICH EMIT SO_2

	Industry	Sources	Emissions
1.	Sulfuric Acid Manufacturers	Production unit	4 lbs SO_2/ton of acid produced -- maximum 2 hour average
2.	Petroleum Refining	Fuel gas combustion device	No fuel gas which contains H_2S in excess of 230 mg/ cm (10 grains/10 .t^3) may be burned. (Alternative limitation on SO_2 release equivalent to the H_2S restriction.)
3.	Primary Zinc Smelter	Roaster and any sintering machine that eliminates more than 10% of the sulfur in the zinc sulfide ore	SO_2 discharge is not to exceed 0.065 percent by volume

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    - Liquid Waste Control, Columbus, Ohio
    - Acme Disposal, Columbus, Ohio
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APPENDIX A

OUTLINE OF TAPE CONTENTS

A.1 Tape Characteristics

Fixed Length Records, 84 characters/record

10 records/block

BCD
BOD BPI
7 Track
No Label

Even Parity

A.2 Tape Format

Card Type 1 - Company Header Records

Format (1H1, I4, AB, 2X2I4, I3, 2F7.2, I1)

SEQUENCE NUMBER
8 Character Plant Identification County/City/Plant
Number of Cards in Company File
Number of Stacks in Company File
New Plant Flag--Nonzero for Growth Plant
Growth (Increase to Year 1980)
Growth (Increase to Year 1985)
Whole Plant Switch--Nonzero, Card Type 5 Follows

Format (3(1H1, 8F9.2/))

Hourly Fuel Consumption by Steam, 10^6 BTU/Hr
Hourly Fuel Consumption by Steam, SCC Units/

Hourly Fuel Consumption by Steam, 8 Fuel Types, 10^6 BTU/Hr
Hourly Fuel Consumption by Steam, 8 Fuel Types, SCC Units/Hr
Hourly Fuel Consumption by Steam, 8 Fuel Types, Tons SO_2/Hr

Format (3(1H1, 8F9.2/))

Same as Fuel Combustion for Steam, Above, Only for Processes

Card Type 2 - Stack Header Records

Format (1H2, 3I4, 4E15.7/1H2, 4E15.7)

Stack Number (1-?)	
Number of Fuel Combustion Units for Steam	
Number of Process Units	
Stack Boiler Design Rate	10^6 BTU/Hr
Stack Fuel Combustion Rate, Aug	10^6 BUT/Hr
Allowable Fuel Combustion Reg, SO_2	Tons/Hr
Allowable Process Reg, SO2	Tons/Hr
Stack Height	Feet
Stack Diameter	Feet
Stack Temperature	°F
Stack ACFM	ACFM

Format (1H2, 5F12.3)

Maximum Stack F. C. Rate	10^6 BTU/Hr
"Steam" Emissions (Maximum)	Tons/Hr
Process Emissions	Tons/Hr
Total Fuel Combustion Emissions	Tons/Hr
Stack Process Weight Rate	Tons/Hr

Format ( )

The Stack Specific Fuel Consumptions, as in the Plant Summaries.
6 cards.

Card Type 3 - "Steam" Records

Format (1H3, 6F 12.3)

Boiler Design Rate	10^6 BTU/Hr
Average Boiler Rate	10^6 BTU/Hr
Maximum Boiler Rate	10^6 BTU/Hr
Sulfur Oxide Emission Rate	Tons/Hr
Maximum SO_2 Emission Rate	Tons/Hr
Operating Hours	Hours/Yr

Format (1H3, A10, 5E13.5) (5 of these cards)

SCC Code	
Average SCC/Hr	
Maximum SCC/Hr	
Sulfur Content	Percent by Weight
Heat Content	10^6 BTU/SCC

Card Type 4 - Process Records

Format (1H4, 3E15.7/1H4, 3E15.7,I5/1H4,3E15.7, I5/1H4, 3F12.3, I5, F12.3)

Process Weight Rate	Tons/Hr
Process Emissions	Tons/Yr
Allowable Emissions	Tons/Hr
Capital Cost for Nonfuel Control Option	10^6\$/Yr
O&M	10^6\$/Yr
ΔEnergy for Electricity	10^6 BTU/Yr
Life (Remaining Life of New Equipment)	Years
BTU of Fuel Consumed	10^6 B/Hr
BTUMAX of Fuel Consumed	10^6 B/Hr
Sulfur Oxide Emissions of Fuel Consumed	Tons/Hr
Number of Fuels	
Scale Factor for Capital Cost of Grass-Roots Facility	
Scale Factor for O&M of Grass-Roots Facility	
Controlled Emissions	Tons/Hr
Control Regulation	
0) = General Process Weight	
1) = Sulfuric Acid (6.5·PWR/2000)	
2) = H_2S Content (PWR=Annual c.f. of Fuel Gas)	
ΔE for Steam Reheat	10^6 B/Yr

Format (1H4, A10, 5E13.5) (5 of These Cards, Fuel Consumption Only)

SCC Codes	
Average SCC/Hr	
Max SCC/Hr	
Sulfur Content	% by Weight
Heat Content	10^6 B/SCC

Card Type 5 - "Whole Plant"

Format (1H5, 3F12.3, I3/1H5, 4F12.3, F12.0)

Capital Cost	10^6\$
O&M	10^6\$/Yr
ΔE - Electric Energy	10^6 B/Yr
Life (Remaining)	Years
Scale Factor for New (Grass Roots) Capital	
Scale Factor for Grass Roots O&M	
Controlled Emissions	Tons/Yr
Actual Emissions	Tons/Yr
Annual SCC (Fuel Gas)	Cubic Feet/Yr